EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 47

DATE: Tuesday, August 20, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

(416) 482-3277

2300 Yonge St., Suite 709 Toronto, Canada M4P 1E4

EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Tuesday, the 20th day of August, 1991, commencing at 10:00 a.m.

VOLUME 47

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

S T A F F :

MR. M. HARPUR	Board Counsel
MR. R. NUNN	Counsel/Manager, Informations Systems
MS. C. MARTIN	Administrative Coordinator
MS. G. MORRISON	Executive Coordinator

Farr & Associates Reporting, Inc.

A P P E A R A N C E S

B. CAMPBELL	)	ONTARIO HYDRO
L. FORMUSA	)	
B. HARVIE	)	
J.F. HOWARD, Q.C.	)	
J.C. SHEPHERD	)	IPPSO
I. MONDROW	)	
J. PASSMORE	)	
R. WATSON	)	MUNICIPAL ELECTRIC
A. MARK	)	ASSOCIATION
S. COUBAN	)	PROVINCIAL GOVERNMENT
P. MORAN	)	AGENCIES
C. MARLATT	)	NORTH SHORE TRIBAL COUNCIL,
D. ESTRIN	)	UNITED CHIEFS AND COUNCILS OF MANITOULIN, UNION OF ONTARIO INDIANS
D. POCH	)	COALITION OF ENVIRONMENTAL
D. STARKMAN	)	GROUPS
D. ARGUE	)	
T. ROCKINGHAM		MINISTRY OF ENERGY
B. KELSEY	)	NORTHWATCH
L. GREENSPOON	)	
R. YACHNIN	)	
J. RODGER		AMPCO
M. MATTSON	)	ENERGY PROBE
D. CHAPMAN	)	
A. WAFFLE		ENVIRONMENT CANADA
M. CAMPBELL	)	ONTARIO PUBLIC HEALTH
M. IZZARD	)	ASSOCIATON, INTERNATIONAL INSTITUTE OF CONCERN FOR PUBLIC HEALTH
G. GRENVILLE-WOOD		SESCI
D. ROGERS		ONGA

APPEARANCES
(Cont'd)

H. POCH	)	CITY OF TORONTO
J. PARKINSON	)	
R. POWER		CITY OF TORONTO, SOUTH BRUCE ECONOMIC CORP.
S. THOMPSON		ONTARIO FEDERATION OF AGRICULTURE
B. BODNER		CONSUMERS GAS
J. MONGER	)	CAC (ONTARIO)
K. ROSENBERG	)	
C. GATES	)	
W. TRIVETT		RON HUNTER
M. KLIPPENSTEIN		POLLUTION PROBE
N. KLEER	)	NAN/TREATY #3/TEME-AUGAMA ANISHNABAI AND MOOSE RIVER/ JAMES BAY COALITION
J. OLTHUIS	)	
J. CASTRILLI	)	
T. HILL		TOWN OF NEWCASTLE
M. OMATSU	)	OMAA
B. ALLISON	)	
C. REID	)	
E. LOCKERBY		AECL
C. SPOEL	)	CANADIAN VOICE OF WOMEN FOR PEACE
U. FRANKLIN	)	
B. CARR	)	
F. MACKESY		ON HER OWN BEHALF
M. BADER		DOFASCO
B. TAYLOR	)	MOOSONEE DEVELOPMENT AREA BOARD AND CHAMBER OF COMMERCE
D. HORNER	)	

INDEX of PROCEEDINGS

	Page No.
PAUL JONATHAN BURKE, AMIR SHALABY; Recalled. JULIA MARION MITCHELL, MARION ELIZABETH FRASER, LYN DOUGLAS WILSON, WILLIAM OSBORNE HARPER; Sworn.	8371
Direct Examination by Mr. B. Campbell	8376

L I S T of E X H I B I T S

No.	Description	Page No.
256	The Annual Environmental Performance Report for 1990, dated June 1991.	8369
257	Fuel Switching Potential (Ontario) by the year 2000, dated July 1991.	8369
258	Scenarios for Demand Management including fuel switching and standards.	8369
259	1989 Demand Management Plan and the net impact of programs on the load forecast.	8372
260	Overheads to be referred to by Panel 4.	8372
261	Interrogatory No. 4.26.16.	8395
261.2	Interrogatory No. 4.9.3.	8425
261.3	Interrogatory No. 4.7.4.	8465
261.4	Final report of the thousand house study contained in the Program Concept Reference Document.	8493
261.5	Interrogatory No. 4.7.139.	8549

---Upon commencing at 10:01 a.m.

THE CHAIRMAN: Please be seated.

We have new microphones as you may notice and we will see how they work out. I hope the microphone people are here to check and they are.

All right. There's a couple of notices: One, I don't know how this happened, but there was a misunderstanding. We will not, not be sitting on Friday of this week. I hope that won't unduly inconvenience anybody, but we don't intend to sit on Friday of this week.

Secondly, we have had a request by the Ontario Federation of Labour for status as a part-time party. This application was made by letter. We are proposed to grant that status unless anybody here wants to make submissions to the contrary.

There have been, since we adjourned in July, some additional exhibits filed by the Proponent. They have been assigned numbers. They are the Annual Environmental Performance Report for 1990, which is dated June 1991, which has been given Exhibit No. 256; Fuel Switching Potential (Ontario) by the year 2000, dated July 1991, which has been given Exhibit No. 257, and Scenarios for Demand Management including fuel switching and standards, which has been given Exhibit

No. 258.

---EXHIBIT NO. 256: The Annual Environmental Performance Report for 1990, dated June 1991.

---EXHIBIT NO. 257: Fuel Switching Potential (Ontario) by the year 2000, dated July 1991.

---EXHIBIT 258: Scenarios for Demand Management including fuel switching and standards

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Thank you, Mr. Chairman. As you know, we will be proceeding today with the Demand Management Panel.

Just before I proceed, I should tell you that I am being assisted on this panel by Mr. Jim Lane, who is assisting generally on the case and has taken some of the particular responsibilities for this panel.

I think the first thing I will do before proceeding to some administrative matters is perhaps get the witnesses sworn. I am going to just give you the names generally and then --

THE CHAIRMAN: Mr. Greenspoon?

MR. GREENSPOON: Sir, I would have a submission before Mr. Campbell proceeds with Panel 4 regarding unanswered interrogatories and material that I think is necessary before Panel 4 starts.

THE CHAIRMAN: Well, we will deal with

that later today, Mr. Greenspoon. I think we would like to get started in Panel 4.

MR. GREENSPOON: All right. Thank you.

THE CHAIRMAN: We will do that this afternoon.

MR. GREENSPOON: Fine, thank you.

MR. B. CAMPBELL: Sitting closest to the Board is -- I have forgotten it goes off after every five seconds so I will try and remember.

Sitting closest to the Board is Ms. Julia Mitchell; next is Ms. Marion Fraser. I should say Ms. Mitchell is Senior Program Supervisor of the existing housing section, residential and agricultural programs, part of the Energy Management Branch.

Ms. Marion Fraser is next. Ms. Fraser is Manager of the Commercial Programs Department, program management division, again of the Energy Management Branch.

Next is Mr. Doug Wilson who is Manager, Planning and Evaluation, also of the Energy Management Branch.

The panel and intervenors will be familiar with Mr. Paul Burke who is Manager of the Load Forecast Department in economic and forecast division. Mr. Burke, of course, appeared on Panel 1.

Next is Mr. Bill Harper who is Manager, Rate Structures, Program Support and Services, Energy Management Branch; and finally, Mr. Amir Shalaby who is coordinator Demand/Supply Plan Review, system planning division and he, of course, has appeared in Panel 3.

I have reminded Mr. Burke and Mr. Shalaby that they remain under oath in these proceedings and perhaps if the other four witnesses could be sworn.

PAUL JONATHAN BURKE,
AMIR SHALABY; Recalled.
JULIA MARION MITCHELL,
MARION ELIZABETH FRASER,
LYN DOUGLAS WILSON,
WILLIAM OSBORNE HARPER; Sworn.

MR. B. CAMPBELL: Just before we proceed with this panel, I have I guess two additional filings to make. One is a correction of errata for Exhibit 25 and Exhibit 76. Everyone will be familiar with these. Exhibit 25 is the 1989 Demand Management Plan and Exhibit 76 was referred to as well in Panel 1 and is the net impact of programs on the load forecast.

Perhaps if I could get the next exhibit number for these.

THE CHAIRMAN: That will be number.

MS. MORRISON 259.

THE CHAIRMAN: 259.

---EXHIBIT NO. 259: 1989 Demand Management Plan and the net impact of programs on the load forecast.

MR. B. CAMPBELL: And Ms. Formusa has copies of these, together with the next exhibit number which should be attached, in my submission, to the following document. I believe the Board has been provided with copies. It is the overheads that will be referred to by Panel 4.

THE CHAIRMAN: That will be 260.

MR. B. CAMPBELL: And again we have copies here that we can hand out.

---EXHIBIT NO. 260: Overheads to be referred to by Panel 4.

MR. B. CAMPBELL: Now, Mr. Chairman, I am not sure that the next item needs an exhibit number. I faxed yesterday to all of the parties who had received the original Exhibit 258 a revision to page 1 of that exhibit and I believe it was also provided to the Board.

It corrects a sentence in the introduction of Exhibit 258. The original sentence in the paragraph of the introduction, it is about -- it is the second last sentence in the introduction paragraph. It originally read that:

"The impact of standards in the '90

load forecast had already been netted out in the results presented in Section 6 of Exhibit 258."

In fact, that had not been done and the sentence should read:

"The impact of standards 53 megawatts assumed in the 1990 load forecast has not been netted out in the results presented in Section 6."

We have sent out a corrected page to everyone. I am not suggesting that we give it a new exhibit number.

THE CHAIRMAN: That will be satisfactory.

MR. B. CAMPBELL: Now, perhaps I could just briefly outline for the panel the matters that we expect to be covering over what I expect will be the next two days of direct testimony.

There will be an introduction by Mr. Wilson. It will be basically addressing Hydro's commitment to demand management and will give some context to Exhibit 258 and Hydro's current thinking in light of the changed circumstances for demand management in Ontario.

We will then proceed to discuss certain demand management concepts which we feel are important

to an understanding of this topic and the actions that are being taken in this important area.

The third area is a comprehensive review of demand management opportunities; that is, the potential for demand management.

We will then turn to a discussion of the kinds of program initiatives, both from the sense of the general objectives for the programs and some discussion of current programs in the various sectors.

...

[10:13 a.m.] We will conclude that section with basically a restatement of the conclusion as to Hydro's position as to the amount of demand management that should be relied on for planning purposes. That, I think will have become clear over the course of the preceding testimony, but we basically feel that by the end of the fourth major section, we hope to have established a reasonable basis for Hydro's conclusion as to the extent to which demand management should be relied on in light of the circumstances that we now face.

The final section of the testimony will deal with four sort of specific matters, which we thought we'd give some particular attention to. They will be issues surrounding how one -- comparisons of electrical efficiency improvement. There are a range of issues as to how those comparisons or how the amount of potential gets calculated, and we want to make it clear that one has to be careful when walking through this particular thicket, and Mr. Burke will be addressing that.

There are some rate matters that we will be addressing in light of the interest that has been shown. In those matters, there are some issues surrounding the use of program incentives, that is

financial incentives, and there we would like to give some particular attention to Hydro's role with respect to standards and mandation.

THE CHAIRMAN: I am sorry?

MR. B. CAMPBELL: With respect to efficiency standards and mandation. That is, Hydro's role in supporting government initiatives in these areas, and the importance that Hydro sees for its efforts in this area.

And with that little road map, I think we better get started.

DIRECT EXAMINATION BY MR. B. CAMPBELL:

Q. Mr. Wilson, I'd like to start with you, recognizing that this panel is going to address Hydro's plans to slow the growth of electricity demand by a number of demand management techniques, and just to lead off, I'd ask you to tell the panel the role that Hydro has taken on, or has given demand management, in its Demand/Supply Planning.

MR. WILSON: A. Demand management is Hydro's top priority for Demand/Supply Planning, planning for the future. Our goal is to get as much reduction in the rate of growth of electricity demand as we can through economic demand management programs. And it is our aim to be or to have the most

comprehensive and effective energy conservation effort in North America.

The 1989 Demand Management Plan, which is Exhibit 25, represented our best estimate of what could be accomplished through demand management, when the Demand/Supply Plan was released. But our position has always been that if we can do more, we will.

The point I'd like to leave you with is that we recognize demand management as the preferred resource. The longer we can postpone the need for new generating stations, the better we will be doing.

3278 MW.
1984 D/M.

Q. Now, if I look at the 1989 Demand Management Plan, which is Exhibit 25, I see that you are aiming at a reduction of 2,000 megawatts by the year 2000 through electricity efficiency improvements, another 1,000 megawatts with load shifting, and about 700 megawatts through peak clipping, and we will come back to these terms somewhat a bit later. But the question I have for you now is as to whether your expectations have changed in the intervening period?

A. Yes, they have. I expect that some parts of the plan will undergo major changes. We will be describing some of the possible changes in the next couple of hours, and elaborating on the more significant points a little later on.

Within the policy framework, and considering the demand management tools that we had available when the plan was developed, our targets were ambitious. But since the plan was developed in 1989, there have been some significant changes in the policy environment for demand management. Last November the government of Ontario asked us to double our efforts, and $240-million was diverted from preengineering of supply options to demand management programs.

In early June, the government proposed changes to the Power Corporation Act, and three of these changes have significance for demand management.

① The most important change is that we will be able to take an active role in getting people to choose or switch to other fuels, for both a customer and Hydro benefit. This replaces a ban on fuel switching programs and opens up substantial new opportunities for us and our customers. check Act ?

② Another important change is a provision that will allow us to help Ontario industry develop energy efficient products and services. This will allow us to work directly with industry to push back the frontiers of energy efficiency in Ontario.

③ The third change, which affects the municipal utilities, deals with the accounting

treatment of demand management costs, and was described by the Minister of Energy as being made to encourage greater participation of municipal electric utilities in conservation programs.

Last November the government indicated that it was prepared to be more pro-active in the use of standards and regulations to capture conservation potential. Then, in late June, the Minister of Energy proposed a wide range of aggressive energy efficiency initiatives in a consultation workshop.

get further details

Among these initiatives were proposals for stringent energy efficiency regulations for products and building codes. Now prior to these developments the government had been proceeding cautiously with energy efficiency standards. The range of policy options open to the government, range from simple harmonization of appliance standards with the United States through to some very agressive measures that are being taken in some American jurisdictions.

Back in May, Mr. Burke mentioned that the demand management forecast would be affected by any significant change of government policy, and we believe that will be the case.

Q. Now at the time of the scoping session for this panel, a number of intervenors

expressed concerns about the effects of the recently announced legislative exchanges, and the role that fuel switching standards and regulations will have on your expectations for demand management. Are you in a position to be able to address those concerns?

A. Yes, but to a degree. While the direction of government policy is clear, the policy is not defined yet in operational terms. So, we will discuss a number of cases that span a range of policy positions. This will include consideration of a wide range of demand management tools, programs, standards, fuel switching, rates, strategic procurement, energy efficiency industry development and so on.

Now, drawing on this information that we have presented, we have concluded that it is reasonable to plan on an additional 1,500 megawatts of savings by the year 2000, on top of the 2000 megawatts that are already identified in the Demand/Supply Plan. This change, when added to our load shifting and peak clipping efforts, means that demand management should reduce electricity demand by the year 2000 by 5,200 megawatts.

Now, that is a very abstract concept, so let me put it into perspective. 5,200 megawatts is about 20 per cent of the peak demand in Ontario now.

It is more than double the entire demand of the province of Saskatchewan. It is 50 times the demand of a city the size of Niagara Falls. It is 160 times the demand of U of T's downtown campus. And it is over 600 times the electricity sales to Bracebridge. I hope that helps everybody get a good perspective of what we are setting out to do.

Q. Now, in order to achieve these objectives, what steps have you already taken to design and implement demand management programs?

A. We have done a number of things over the last two years that we feel are vital to success in demand management, and there are seven I'd like to talk about. They are on the screen here.

The topics are reorganization, staffing and budgets, programs in the field, research efforts, analytical tools, ally development and monitoring and evaluation.

...

[10:24 a.m.] THE CHAIRMAN: Perhaps we should just note for the record that this is overhead No. 1 of Exhibit 260.

MR. B. CAMBPELL: Q. And given your comments that these steps have been put in place over the last two years, I would perhaps just ask you to, elaborating on each of these points, to comment on whether you see demand management now as being a simple matter of administering programs?

MR. WILSON: A. Well, not really. We are in the early days of this effort and we are learning as we go along. We expect that we will be making changes in the light of our experience.

Q. All right. Could you elaborate then on the seven points that you mention, the first one had to do with reorganization?

A. Certainly. In 1989 we reorganized to get better at bringing our expertise in energy matters to our customers. The focus of the energy management branch was reduced to one primary goal, getting demand management results through program design and delivery.

The regions branch trimmed away peripheral tasks from the customer energy services staff so they could focus fully on demand management program implementation.

These customer service staff were moved from six regional centres out to 20 local field offices so they could work in close contact with allies and customers.

Having our energy experts located close to customers across the province is a major strategic advantage.

Just a few weeks ago Hydro's Board of Directors approved a realignment of senior management responsibilities. One of the changes creates a new energy management and corporate relations branch, with a senior vice-president who reports directly to Hydro's chair, Marc Elieson. This change indicates the strategic importance being given to demand management and reflects the importance of partnership with the Ontario public in achieving our conservation and demand management aspirations.

Q. The second item you mentioned was resources.

A. Well, the budget for the energy management function has increased substantially. In 1988 it was $56-million, this year it's 182-million, and we plan to increase the budget to $334-million in two years time in 1993.

Q. What have been the developments with

respect to demand management programs?

A. In the last two years we have created and implemented over 30 new demand management programs, expanding from information-only-type programs to a broad portfolio of programs that use a variety of marketing tools such as rebates, direct installation, audits and low interest loans.

We have designed programs to establish a foundation for future success by demonstrating that real savings can be achieved, and that we are prepared to work with industry allies and that people can count on our expertise in energy matters.

We have used a full array of advertising and promotion techniques to get people interested in energy efficiency, to show them that they can rely on us to provide impartial advise, to help them identify the measures that they can take personally and to invite them to take advantage of our demand management programs.

Marketing theory is a guide to program design, but we believe we have to learn in the real world.

Q. And the next topic you wanted to address was research effort.

A. We have assessed the potential for

demand management in Ontario. We have studied the most successful utility programs in North American so that we could learn from other people's experience.

We have conducted extensive market research to assess our customers and allies' perceptions of where the best opportunities are, what the barriers to success are going to be, and what they think of various program design proposals that we are coming up with.

We have conducted extensive test marketing in Ontario, and some examples of those you will be hearing of later are energy efficient motors, streetlighting, refrigerator buy-back programs, and so on, to test on the street how this is going to work.

We have conducted research and development in the technical area that has accelerated the development of new energy products. Things like burner-assisted and ground-source heat pumps. Our research assistance program has put our expertise to work for the benefit of over 100 industries since 1982, working on things likes infrared process heating which can result in substantial productivity improvements for manufacturers.

We have also provided technical leadership by developing test methods to assess the

efficiency of electrical products and building elements. One of the most recent of these is a portable motor efficiency measurement system, we can carry it right into a factory, testing right on the factory floor.

Q. And with respect to analytical tools?

A. We have developed analytical tools to help us screen the demand management concepts that have merit from the ones that don't, and then to help us refine the designs of demand management programs.

We have also been strengthening our ability to analyze the demand for electricity with state-of-the-art end-use load forecasting models which were discussed by Panel 1.

Q. And the next item you wanted to address was ally development.

A. We have been working closely with energy industry allies to ensure that our programs will be workable. A number of municipal utilities have been active partners in developing and testing program ideas.

We have run extensive training programs to introduce new energy efficient technologies to contractors, consulting engineers and municipal utility staff. And we have become closely involved in

supporting the trade of professional organizations in Ontario that our allies use to share information and promote high standards of service.

Q. And the final item is monitoring and evaluation.

A. We have set up a monitoring system to track our progress and our programs are fine-tuned as we get feedback from customers, allies and our field staff. We audit the results that are reported to ensure the accuracy of the information.

We certainly don't expect every program is going to work perfectly. As partners in demand management we know that we can rely on our allies and customers to tell us when something isn't working and we are committed to making changes when they are needed to get those programs working properly.

As this dialogue continues, our planners are making adjustments that factor our experience with programs into expectations for the future. This ensures that demand management is fully integrated with the Corporation's forecasts and plans.

Q. What do you see as being the involvement of the Ontario community generally that will be required to achieve your objectives in demand management?

A. We believe that real success in demand management will require a fundamental shift in people's behaviour. We will be working to accomplishing a culture shift in Ontario, making energy efficiency as important to everyone as protection of the environment is today.

We realize that we have to reach every person in Ontario with our message and our programs, every home, every office, every factory and every farm.

It's obvious that Ontario Hydro can't do this alone. As the Lieutenant Governor, the Honourable Lincoln Alexander said in the throne speech last November:

> "These new energy directions will be a challenge to all the citzens of Ontario to take part in individual and community efforts to ensure the most efficient and environmentally sound use of our energy resources."

To be really effective we have to go beyond working with institutions that represent customers and industry allies; we have to get the active participation of service clubs, churches, community groups, to stimulate local initiatives for energy efficiency; to work with schools and colleges

and universities to provide the training needed to advance energy efficiency; to work with architects, consulting engineers, developers and builders to specific energy efficient designs in products; to work with manufacturers distributors and others to make and service efficient products, and finally, we have to work with all levels of government: federal, provincial, and municipal, to set product efficiency standards, to enhance building codes and to set supportive economic and energy policies.

Q. Overall then, how would you summarize Hydro's commitment to demand management?

A. Hydro's goal is to contribute as much as we can to making Ontario energy efficient. To do that, we are going to make sure that we have the most comprehensive and effective energy conservation effort in North America. We will work with customers, industry allies, government and all other parties who can contribute to this objective. We believe that we have the skills and the resources to make a strong contribution across the full range of demand management efforts.

Q. Now, Mr. Wilson, against that background I want to review some of the concepts relevant to demand management, and I guess my simple

first question is to start with exactly what is meant by that term "demand management"?

A. Well, in the North American utility industry there is a fairly technical definition, and it simply is that demand management is any action taken by an electric utility intended to influence the level or timing of customers' electricity demand.

Now clearly, just any change in electricity demand won't do.

Demand management starts with a recognition that what people want -- they buy electricity to satisfy a need.

...

[11:32 a.m.] They want a warm house. They want a well-lit office and they want to be able to manufacture their products.

In many cases, there are ways of satisfying these needs more effectively and at lower costs than most people are unaware of, and that is where demand management programs come in. They offer customers information and incentives to overcome barriers to reduce the overall cost of satisfying these electricity service needs.

Demand management is a vital part of utilities' efforts all across North America to ensure that customers' needs for electricity services are satisfied at lowest cost.

Q. All right. Can you tell us then about the different types of demand management, please?

A. This figure --

Q. And that is page 2 in Exhibit 260?

A. This figure which is taken from Exhibit 3 on page 7-3 illustrates five ways that demand management can affect the daily demand pattern for electricity. And depending where you are in North America, utilities are working for different objectives. Demand management can be used to achieve load reduction, to shift load from peak periods to

off-peak periods, to clip the peak, to fill the valleys or just to raise the overall demand for electricity.

In principle, each load shape objective can be legitimate. For utilities that have a large amount of excess generating capacity, demand management efforts are intended to build the load and fill the nighttime valleys.

For utilities with short, severe daily peak demands, demand management is intended to clip the peaks.

For utilities with inexpensive off-peak power to offer and generation reserve margins that are shrinking, demand management efforts are intended to shift the load to the off-peak hours.

For utilities with conservation resources that are cheaper than supply alternatives, such as Ontario Hydro, load reduction is the aim of demand management efforts.

The choice of one or more load shape objectives for demand management thus depends on the situation confronting the utility.

Q. Now, does Ontario Hydro have any programs intended to achieve valley filling or load building?

A. No. As I pointed out earlier --

Q. Now you are going to have to --

A. Thank you.

Q. All right.

A. No. As I pointed out earlier, Hydro's aim is to reduce the cost of electric service by slowing the growth in demand for electricity. So, our programs focus on load reduction, load shifting and peak clipping.

Q. All right. Can you summarize for us briefly how utilities go about achieving load shape objectives?

A. The next overhead which is No. 3 in Exhibit 259 just illustrates --

Q. Sorry, I think it is 260?

A. I am sorry - yes, it is 260 - just illustrates as we did the in the 1989 Demand/Supply Plan that there are several ways of meeting each objective. This shows how we were planning to achieve demand management results at the time the plan was developed.

We plan to use programs for electrical efficiency improvement to reduce load, to use time-of-use rates and thermal cool storage and to direct load control to shift load and rates for discount demand service to achieve peak clipping.

Q. Now, I take it that the tools available to you will be expanded in light of the proposed changes to the Power Corporation Act.

A. Yes, and the most important of these is the removal of the restriction on fuel switching programs. This means that we will be able to create active programs using incentives to encourage customers to use other fuels where it is economic to do so.

Clear examples of opportunities for this are the substitution of natural gas for electricity in residential space and water heating. These programs will be applied to new homes and conversion of the equipment in existing homes.

Q. All right. Now, I would like to turn then for a moment to you, Mr. Harper, and discuss briefly rates as a demand management tool. It has been a topic that has come up from time to time over the course of the preparations and through the hearing.

And I would ask you simply first whether Hydro considers rates to be a demand management tool.

MR. HARPER: A. Yes, Hydro does consider rates to be a demand management tool. Evidence of this can be found in the approved objectives we use to guide our costing and pricing of electricity, in the Demand/Supply Planning Strategy and in the actual rate

forms we use.

Hydro's costing and pricing objectives can be found in the response to Exhibit 4.26.16, and it can be --

Q. I am going to try and get you to turn off the OEB terminology and turn on this hearing terminology. These are referred to as interrogatories.

A. I am sorry.

THE CHAIRMAN: What is the number again, please?

MR. HARPER: 4.26.16.

THE CHAIRMAN: Then we should create an exhibit for this panel that interrogatories is referred to and not filed as an exhibit.

MR. B. CAMPBELL: All right.

THE CHAIRMAN: It will be -- next number?

MR. NUNN: 261.

THE CHAIRMAN: 261.

---EXHIBIT NO. 261: Interrogatory 4.26.16.

MR. B. CAMPBELL: Q. All right, Mr. Harper, go ahead.

MR. HARPER: A. It can be seen from this interrogatory that encouraging efficient use is one of the specific objectives concerned in ratemaking. In fact, the objective dealing with efficiency

specifically reads:

"Rates should encourage efficient use of facilities and resources in the production, distribution and consumption of electricity so as to minimize the cost to Ontario customers over the long term."

THE CHAIRMAN: I wonder if you could speak just a little slower, please. I take it you are reading from something and people have to listen to it and absorb it, if you could just be a little slower.

MR. B. CAMPBELL: Mr. Harper is well used to this admonition. It occurs regularly throughout his testimony and I will make sure it is repeated at regular intervals as required.

Q. All right, Mr. Harper, perhaps you could indicate then how rates are used to encourage efficient use.

MR. HARPER: A. Encouraging efficient use through rates is accomplished in two ways: First, by setting rates that reflect costs, customers are informed of the system implications of their consumption decisions; second, by offering customers rate choices, we give them the opportunity to control their electricity bills and at the same time encourage consumption decisions that benefit our system overall.

Turning from the objectives and looking directly at the development of the Demand/Supply Plan, the role of price and rate structures is addressed in the Demand/Supply strategy, Exhibit 74, chapter four.

The strategy specifically recognizes the potential for the contribution of time-of-use rates and of special rates for non-standard conditions of service in order to manage demand.

Finally, we have both time-of-use rates and interruptible power rates in place, the same main rate initiatives used by other utilities active in demand management.

Q. Are there considerations other than efficiency in the ratemaking process?

A. Yes. I believe it is important to emphasize that efficiency is not the only objective in ratemaking, and that the desire for rates designed specifically to encourage demand management must be traded off against other objectives such as meeting our annual revenue requirement, tracking costs fairly amongst our customers and having rates that are stable, practical and acceptable to the customer.

These objectives have evolved over the course of hearings before the Ontario Energy Board and in particular, a special inquiry to the principles for

costing and pricing of electricity in Ontario and have generally been endorsed by both the Board and our customers. And, of course, they have to be applied in a way that is consistent with the power at cost philosophy embedded in the Power Corporation Act.

Q. Now, Mr. Shalaby, I want to turn to you for a moment and have you describe for us how demand management generally affects the electricity system.

MR. SHALABY: A. Well, the demand management measures that Mr. Wilson indicated that Hydro is giving priority to, particularly the efficiency improvement type of options, would generally reduce a demand for electricity. They reduce it compared to what otherwise would happen. Without the demand management programs, the demand for electricity would be higher.

And as a result of that reduction in demand, there are three related impacts on the electricity system. There are impacts to do with facility use, with fuel use - generally they are reduced - need for the existing system to operate. They are a reduced need for expansion, delayed need for expansion. So, the first impact is a reduction in the use of the existing system and the need for facility

expansion.

The second impact has to do with dollars, with cost, and it is to do with lower costs of producing electricity. If you are not using your facilities, if you are not burning fuel, there are less costs and less dollars going into making electricity on Ontario Hydro's side of the business.

On the other hand, there is also less product sold, less electricity sold, and that means there are less revenues coming into Ontario Hydro, less revenues coming into the municipal utilities. So that is a second impact to do with the balance sheet and to do with costs.

The third impact has to do with the environment. The less use of the existing facilities, the less production of electricity, the fewer the impacts on the environment related to, for example, acid gas emissions, effluents into the atmosphere and so on. So, the fewer kilowatthours produced, the less impact on the environment, both from reduced generation and transmission systems.

Q. I would like to deal with these impacts one at a time and start with the use of the existing system and the need for electricity facility expansion.

Could you expand on that slightly, please?

A. When an electrical efficiency improvement is implemented - an example would be a retrofitting of an efficient lighting mechanism in a factory or an efficient motor - the immediate impact is a reduction in the use of the existing system and a reduction, for example, in fuel use, reduction in transmission losses. So, the very first thing that happens is reduction in electricity generation fuels and losses.

In the longer term, the efficiency improvements will add up. They increase in size, they add up and start deferring and perhaps eliminating the need for expanding the electricity system, the need for expanding the transmission network and the distribution network.

Q. And do all demand management options have similar impacts on the use of the existing system and the need for expansion?

A. No, they don't. And here, really, we are going over material that we have covered before in the different panels, but to recap, different options have different impacts on the electricity system.

For example, options that save

electricity during peak hours, or mostly during peak hours, would have a greater reduction in the use of fossil fuels, for example, than options that operate mostly during off-peak hours.

Also, the more coincidence, the more match between the saving and the 16-hour peak period - and you would recall the 16-hour peak period that we talked about before is a period between 7:00 a.m. and 11:00 p.m, that is a period of highest demand typically on our system - the more an energy efficient option saves electricity during that period, the more it will contribute to reduction in the need for generating capacity and the need for expanding that generating capacity. So that is a difference between one option and another.

Another distinction between the impact of options on the system is the location and the voltage level at which the efficiency improvement is hooked up to the system. If it is hooked up at a higher voltage level, it has less impact on reducing distribution facilities, for example, than if it were connected at the home. At the home it will have more impact producing the distribution facilities of a municipal utility.

And finally, of course, if an option

lasts for 10 or 15 years, it will have a greater impact in reducing electricity system requirements than if an option lasts only one year or two years. So, the life of an option is another factor that makes the options different from one another.

Q. And I would like you, please, to give an example that illustrates these impacts.

A. All right. I would like to refer to page 4 of Exhibit 260 and the diagram shows four steps really that I would like to take the Board through to explain how we determine the impact of an energy efficient option on the electricity system.

The first thing we do is determine the impact of a single measure. Perhaps we can think of an efficient refrigerator. So, the top box, think of an efficient refrigerator, and for illustrative purposes, let's say it consumes one kilowatt less than a less efficient refrigerator. So, that is the first thing: Describe the product, describe how more efficient one fridge is compared to the other.

The next step is something to do with the behavior of a very large number of refrigerators on our system. So, if we say there is a million efficient refrigerators out there, the collective impact of those million refrigerators is not going to be a million

kilowatt reduction in demand.

And the reason for that is that not all the refrigerators are on at the same time. Some are on; some are off. A refrigerator cycle, they work part of the time and they work at different times of day and different times of year at different rates.

So, the point to make here that I would like to leave with you is that you do not add up the million refrigerators times one kilowatt and say that is the impact on the electricity system.

...

[10:43 a.m.] That works with all options. Lighting systems are not all on at the same time, air conditioners, heating systems and so on. The measures are on and off alternating. So, that is a step that we call the diversified load impact. Diversified means how the entire family of efficiency measures behave collectively.

We particularly pay attention to the impact at the 16-hour peak period. Again, I hate to repeat that too many times, but the significance of that is that as we go on in describing to you the potential in Ontario of demand management, we will always decribe it in terms of the diversified impact during the 16-hour peak period. That is the currency that we use or the definition of impact or potential that we use in describing demand management. How much would it reduce demand during the 16-hour peak period as a diversified group of measures.

So, that takes us to the second block on page 4 of Exhibit 260. The second two blocks are old ground. We will go through them quickly. That is when savings occur at the end-use, there are additional savings to do with transmission distribution losses. So, we count that as well. If you save one kilowatt of the customer use, you save more than that at the

generating station.

And finally, if you reduce firm demand by a certain amount, you reduce the generating capacity requirements by even more than that amount, typically 20 to 25 per cent, and that is the reliability reserves that we talked about extensively before.

So, the last two blocks are really translating the saving at a home or a factory or an office to the saving at the generating system. They generally increase. One kilowatt saving at the home translates typically to something like 1.3 or 1.35 kilowatts at the generating system, because of the transmission losses and the reliability requirements.

So, that really sums up quickly the impact of demand management, particularly efficiency improvements on the electricity systems. There are many more details, but that captures the essence of how the impact occurs.

Q. Now, I'd like to you move to the second impact of demand management that you spoke of, and that is changes in the costs and revenues to utilities. Again, some of this has been -- I guess quite a bit of it has been discussed in Panel 3, but could you just briefly outline for the Board how costs change as a result of demand management programs?

A. The reduction -- there is more work on this panel than the previous panel with these mics. I thought I'd seen the worst of it, but...

There is a reduction in Ontario Hydro supply-related costs, because of a direct consequence of reducing fuel use, reducing expansion costs, facility, operation and so on. So, that is a straightforward consequence, and we talked at it at length in Panel 3. We called it the avoided cost. The avoided cost of an efficient system is the saving that occurs because of that efficiency.

What additional things to do with cost, perhaps if you take the perspective of a municipal utility, a municipal utility like North York Hydro, for example, when an efficient refrigerator is installed in one of its customer's premises would buy less electricity from Ontario Hydro. So, there is a reduction in cost to North York Hydro, not because they produce less electricity, but because they buy less wholesale product from Ontario Hydro.

So, in one hand there are savings to Ontario Hydro and the municipal utilities. On the other hand, there are increased costs to do with acquiring the demand management option; with implementing the programs, with monitoring it,

administering it and so on. So, that is the impact on cost. A decrease on one side and an increase, because of the administering and monitoring of the programs.

Q. All right, and how about changes in revenues, the other cost element you spoke of?

A. Revenues change, again, because the utilities are selling less product. Less kilowatthours sold to their customers when their customers implement demand management and efficiency improvement. This loss in revenue has the direct impact of raising the unit price of electricity. That is, the price per kilowatthour of electricity in the short-term would go up. And the reason for that is that the electricity business has got a large component of fixed costs. There is a large amount of fixed costs on the system that have to be recovered, and if we are selling this product, we have to recover those same large fixed costs from fewer number of sales. So, the price per unit would go up in the short term.

In the longer term, the impact is less clear and less obvious. It really depends on what would otherwise have occurred if demand management wasn't there. What the supply would have cost, when would it have been introduced, what the accounting practices are. So, the longer term impact is more

difficult to determine.

And before I leave the impression that demand management would raise the costs of electricity service, I don't want to leave that impression, it raises the price of the unit of electricity. The kilowatthour price would go up. But the bills that customers pay, the total cost of electricity that customers would pay would depend very much whether they are participants, as we call them, in the demand management measures or not.

If customers participate, if they become more efficient, then their bills could very well go down, even if the price per unit has gone up. They use much less electricity to do the same service. While they pay more per unit, the total bill could very well go down, and that is what we expect, that most customer that participate would be saving on their total bills.

On the other hand, customers that do not participate would observe an increase in their electricity bills as a result of Ontario Hydro's demand management programs.

Q. Now, I want to turn you then, Mr. Shalaby, to the cost effectiveness tests that you use, and given all of the kinds of impacts that you've talked about on the electricity system, how does Hydro

decide if a demand management option is cost effective?

A. Well, that's really, in principal, a very simple comparison, a very simple determination. Demand management is cost effective, if it is likely to cost less than the alternative supply options. So, that is, in a nutshell, the test that Hydro would use to determine whether a demand management option or program is cost effective.

Q. All right, now before you explain how you perform that comparison, can you describe to us what are the costs that are looked at with respect to demand management programs? You have dealt with some of the other utility costs. When it comes to demand management programs, what kinds of costs do you look at for those programs?

A. The demand management programs have costs that are incurred by the municipal utilities, by Ontario Hydro, and by the customers. That is a bit different from the cost of acquiring supply facilities and operating supply facilities that are typically incurred by Ontario Hydro and the utilities. So, the difference here is that we have more than one entity incurring costs, when demand management is acquired and operated.

Examples of costs that are incurred by

Ontario Hydro would be costs to do with program design, with advertising and promoting the efficiency improvement opportunities, delivering the programs, the staff in the field, Mr. Wilson described the customer energy service staff and so on are, and there are incentives that are paid by Ontario Hydro to make the options more attractive to customers. All of those are examples of costs that Ontario Hydro would incur.

Examples of costs that the municipal utilities could incur have to do with delivery of the programs, training of their staff, training of people that deliver the programs, and perhaps some local advertising and promotion of the opportunities in their service territory.

And examples of costs that the customer will incur when implementing demand managements options would include additional capital cost. If an efficient costs more than an inefficient option, there would be premium costs, and the customer typically contributes to that premium cost, and there is also changes in maintenance cost of the equipment that could be negative or positive, but those are examples of costs that the customer will see.

Q. All right, now given that when you are looking at demand management costs, they extend,

Hydro, municipal utilities, the customers. How do you compare all of these with the cost of electricity supply, when you are developing a Demand/Supply Plan?

A. Well, we use the total customer cost test. That may seem to be something from the distant past, but that is from Panel 3. Mr. Cowan introduced the concept of the total customer cost test. And that is the primary test that we use to determine whether a demand management option makes it really into the package of options that Ontario Hydro would be interested in implementing.

If an option passes the total customer cost test, it makes it into the hopper of candidates that can be looked at by the program designers and the energy management branch. If it doesn't make it, then it is rejected and perhaps examined at a later stage. Things have changed, costs have changed, performance has changed and so on. So, the total customer cost test is really the key hurdle that separates successful programs from unsuccessful ones.

Q. Now, can you tell us briefly, please, what your objectives are when you are applying this total customer cost test?

A. Well, I'd like to refer to page 5 of Exhibit 260. And that also was introduced in Panel 3;

I guess they call me a continuity witnesses. What I do is bring things from the past to the present panel.

This is a chart that Mr. Cowan used to describe the perspective that the total customer cost would take. To answer your question of what the objective is of a total customer cost test, it is to ensure that customers collectively, that is the larger perspective, the larger box that includes both Hydro and the municipal utilities, as well as customers, that includes everybody, that family or that perspective will pay the least cost for electricity service in the long term.

So, that is what a total customer cost test will insure. It will insure lowest cost in the long term, because it counts the costs that are borne by all of these entities inside that box.

Q. And again, I would ask you to remind the Board whether there have been any changes in the way the total customers cost test is applied in screening demand management, since the publication of the Demand/Supply Plan?

A. Yes, there has been a change in that we are now adding a 10 per cent premium in evaluating demand management. A 10 per cent premium would favour demand management over supply options that are built by

Ontario Hydro. Hydraulic options also get the 10 per cent premium, but typically demand management enjoys a 10 per cent edge over thermal options, for example. And we discuss the rationale --

THE CHAIRMAN: Over what options? I am sorry.

MR. SHALABY: Thermal options, like fossil fuels and nuclear power.

And we discussed, to a considerable extent, in Panel 3 the rationale for the premium and how it is applied and so on. So, that is a change in the total customer cost test since the publication of the Demand/Supply Plan.

Now, Exhibit 76 which evaluated demand management options for inclusiuon in the 1990 load forecast, uses the 10 per cent premium in evaluating efficiency options. So that has found its way now to the 1990 load forecasts and activities that would go beyond that.

MR. B. CAMPBELL: Q. Could you give us a couple of examples, please, as to how that test is used in screening demand management options in particular?

MR. SHALABY: A. I'd like to refer to page 6 of Exhibit 260. And on that page are two examples of efficiency improvement options that are

taken from Exhibit 76. There are many other examples in that exhibit. Those two examples are meant to illustrate what constitutes a passing of the total customer cost test and what constitutes a failure to pass that test.

The first option on the top of the table is a compact fluorescent lamp in houses or in homes. The four columns in the table, the first one to the left indicates a benefit of the demand management, which is really the avoided costs that are harvested when demand management is implemented. And for the compact fluorescent, the benefit is 5.4 cents per kilowatthour.

The next column shows what the cost of that demand management is, which is referred to in the Exhibit 76 and other exhibits as the life cycle cost of demand management. It is also expressed in cents per kilowatthour, and for that particular option the cost is 4.7 cents per kilowatthour.

And that means, as we move to the third column, that the net benefit of the option is .7 cents per kilowatthour.

...

[11:03 a.m.] So, implementing compact fluorescent lamps that have certain characteristics, for example, they operate for a certain number of hours and live so many months or years and have a certain cost, there are many assumptions associated with that cost benefit analysis that you see here, but given those assumptions, that particular application is seen to be yielding that benefit and therefore it passes the total customer cost test.

The next option on that page is T8 fluorescent lamps with electronic ballast.

A T8 fluorescent lamp is similar to the fluorescent lamps we have here. They are thinner in diameter, they are different in colour rendition, and they are much more efficient in their use of electricity.

Electronic ballast similarly are more efficient in they have less losses and last longer than regular ballast.

That option, if it's used in -- the example here is religious buildings, if it's used only a few number of hours during the week, say 10 hours or 8 hours during the week, that example shows that the benefit is 4.1 cents, the cost is 5.6 cents, and therefore it is not it does not yield positive benefit.

The benefit is minus 1.5. In that particular application the efficiency improvement does not pay back in economic terms, and the reason for that is that it's not used often enough during the week.

Typically T8 fluorescent lamps and electronic ballasts are cost effective in more typical applications, in offices, schools, and so on. So, the reason it's not effective here is that it is not being used often enough or long enough during the week.

DR. CONNELL: Mr. Shalaby, could this be described as dim religious light! (laughter)

MR. SHALABY: Could be.

MR. B. CAMBPELL: Q. Now, there is one correction that I want to draw particular attention to, Mr. Shalaby, in relation to the description in Exhibit 3, the Demand/Supply Plan main report, of the total customer cost test. I don't know that it is necessary for the Board to do it right now, but I want to be really sure that this one is on the record, and perhaps you could just describe the problem that crept into the text there.

MR. SHALABY: A. Well, because we are talking about the significance of the total customer cost test, I would draw your attention to a correction on page 7-6 of Exhibit 3. That correction was made in

Exhibit 86, which was filed on August 24th, 1990. I still do remember a date or two, that's good.

The corrections are on the right-hand column of that page. Maybe I will wait a second for the panel to get their copies.

The top right-hand corner of the page describing the total customer cost test, the top bulletin should read, "program administration and delivery costs," this is the utility's costs of delivering the lighting program, then the correction is to delete the words "including incentives where applicable."

The second correction in the area is to the next bullet, which starts by "changes in customers' operating costs," and the correction is to delete what is between brackets after that, which is, "the customer's bills reduction as a result of lower consumption for lighting."

So, those are the corrections at page 7-6.

Q. Now, with those corrections, I would like you to explain briefly, please, why incentives that may be paid by the utility are not given any special treatment in the total customer cost test, why they are not really relevant to that test?

A. The incremental cost of the demand management measure is really the starting point for the total customer cost test.

If we think of an efficient refrigerator as costing, for example, $200 more than the less efficient one, that is what we call the incremental cost of the efficiency improvement measure, $200.

The total customer cost test puts that entire $200 into the equation. Now, the issue of incentives is really who pays the $200, whether it's the customer buying the refrigerator, whether it's partly the customer and partly Ontario Hydro in the form of incentive, or whether it's entirely paid as an incentive by Ontario Hydro. It is therefore less material who pays the $200 than it is that the cost, the entire cost, the $200 are included in the test. And that's what we do.

So, by including the entire incremental cost we make sure that the entire incremental expenses are included in the test

It would in fact be double counting if we say there is $200 incremental cost plus, let's say, $50 incentives from Ontario Hydro, because the $200 includes that incentive to start with.

So, it is perhaps an easy mistake and we

have made it ourselves in our own exhibit to think that incentives are part of the total customer cost, but in fact if you include the incremental cost completely you have you have accounted for all of that.

THE CHAIRMAN: That explains the first bullet change. It doesn't explain the second one, or does it?

MR. SHALABY: The second one is to do with the incremental costs of producing electricity.

The second bullet says that the costs paid by the customer, the bill paid by the customer is really double counting again.

If we say Ontario Hydro saves on fuel and saves on cost of producing electricity, then we have captured the savings in producing electricity.

If we now go again and say, and the customer saves 4 cents every time he doesn't buy a kilowatthour, that would also be double counting.

So, you have got to capture the cost of saving only once, and you have got to capture the increase in cost only once. And the fact that more than one entity encounters either of these savings or costs is irrelevant. It only occurs once and it finds its way through the system after that.

MR. B. CAMPBELL: Q. All right. Now,

with those corrections, is the total customer cost test the only test used by Hydro to screen demand management opportunities?

MR. SHALABY: A. Yes, it is. It's the only test we use to screen demand management measures, and that is the total cost test, it's really the first change, the first hurdle that demand management options and programs have to pass. If they do, they are considered further for program implementation; if they don't, they are not considered further.

Q. Now, are there other tests other than the total customer cost test which could be used in the screening process?

A. Yes, they are. They are other tests that are used by other utilities, other jurisdictions or, in fact, could have been used in different times.

At Hydro we use additional tests that examine demand management from different perspectives, but we use that at the stage of program design.

What we do is we look at the demand management program or measure from various angles from how would it look, for example, to the customer. Does the customer find enough attraction in the demand management option to adopt it enthusiastically? And the test that would examine that perspective would help

our program designers determine what kind of incentives, what kind of promotion, what kind of packaging is required to make that program attractive to customers.

So, the other tests are used by Ontario Hydro, they are primarily used for program design purposes.

There are other tests in addition do the participants' perspective, something called the ratepayer impact measure test, and I think you will hear enough about it during the testimony and cross-examination. We call the RIM test, R-I-M.

The RIM test is designed to look at the demand management from the perspective of the non-participating customer, the customer that does not implement the demand management option.

It looks at, specifically, the increase in price of a kilowatthour that the non-participating customer will see as a result of a demand management option. So, that's a second kind of test, customer perspective, the non-participating customer perspective, and there are other perspectives to do with the distributing utility.

Q. Just before you go on to those, am I correct that what you have referred to as the RIM test

is also referred to frequently in the literature as the no losers test?

A. It is. And the no losers label that is attached to that test is really to say that to pass the rate impact measures test is to design a program that does not negatively impact on the non-participant. That means that if we introduce a program, the price of electricity does not rise to the non-participating customer. That constitutes passing the RIM test. Therefore, a program that has no losers, the participant wins and the non-participant also wins.

Q. Now, perhaps you could just briefly describe the other test, and then I think you are going to move on and give an example.

A. Okay. Other tests would do with the impact of the demand management from the perspective of the distributing utility. Thinking again of the North York Hydro kind of example where what impact would an efficiency improvement program that Ontario Hydro implements on the distributing utility. They lose revenue, on the other hand, they do not have to pay Ontario Hydro for purchases of electricity.

So, the impact on them could be very different than the impact on either the ultimate customer or Ontario Hydro.

One last test that I would mention here is something called the utility cost test. And that is if we were looking at a narrow perspective of just Ontario Hydro, we compare the costs of producing electricity to the cost of promoting and delivering demand management without looking at the customer cost. So, we look only at the dollars that Ontario Hydro would incur one way or the other. So, it's a little narrower perspective test than the total customer cost test.

So, those are varieties of tests that look at the same program from different angles, from different perspectives, and the primary use for them is to aid in designing programs that are effective and can find their way to the customers.

Q. All right. Now, I would like to you sort of give this a little bit of reality by using a particular example to show how these kinds of tests can apply.

A. I would like now to refer to page 7 of Exhibit 260, and on that page we show the test, the demand management test used in Ontario Hydro to examine the R2000 program. R2000 is an efficient house, it's better insulated and it is better built for less energy consumption.

And in addition to the total customer cost test which is shown on the top of the table, there are four other tests that are used for program design that are shown below the line.

The first line, the total customer cost test, shows that there is net benefit of the R2000 program. The benefit exceeds the cost by $3.2-million, and therefore it passes the total customer cost test.

The entire point of this diagram and the example is to show that while it passes the total customer cost test, if you scan quickly on the right-hand side column you will find that it fails one of the other tests. So, it passes the total customer cost test but it then fails the Ontario Hydro rate impact measures test. It still makes it as a successful program. I think that is the singular most important message that I want to leave here, is that a program does not have to pass all the tests; it just has to pass the total customer cost test.

The Ontario Hydro RIM test, if we use the abbreviation, says that the non-participating customer would really have to subsidize the participating customer to the tune of $13.3-million. The lost revenues and the incentives that have to become part this program exceed the benefit of the

program, or the benefit of the program is lower than the cost if you include the lost revenue and the incentives, and that really is a transfer of money from the non-participating customer to the participating customer.

...

[11:18 a.m.] The other tests show the that distributor, the North York Hydro, would see almost even benefit in costs. The reduction in their bills paid to Ontario Hydro would almost equal the lost revenue that they incur in lost sales.

The utility cost test, which is the fourth line in this table, shows that Ontario Hydro will see benefits of 26.3 and would incur costs of 13.5. So, there is clearly a net benefit to Ontario Hydro.

And the last line is the incremental participant test. It looks at the program from the view, the eye view of the participating customer, and it shows a net benefit as well.

Now, those are complicated formulas to some extent and there is more detail on how those tests are conducted, what costs are included, and those details can be found in Interrogatory No. 4.9.3. And that the interrogatory gives further light into those tests and how they are conducted.

THE CHAIRMAN: 4.9.3?

MR. SHALABY: That's correct.

THE CHAIRMAN: That will be No. 2 of Exhibit 261.

---EXHIBIT NO. 261.2: Interrogatory No. 4.9.3.

MR. SHALABY: Now, one other thing perhaps while we are observing a large number of tests that I can leave with you; that is, the total customer cost test is really a function of - is the measure cost effective or not?

The other tests are in a big way a function of how the program is designed, how much incentive is being paid, who pays what? There is more control on making the other tests go one way or the other. There are more policy instruments. There are more variables to work on on the lower test than on the upper one.

The upper one really is, is this a good option or not? There is not very much you can do about that. The lower one you can play with incentives and with cost sharing and other things to make those tests look different. And that really is the challenge to program designers.

MR. B. CAMPBELL: Q. Now just as a matter of interest, what would the impact be on Hydro's demand management efforts if the screening test for eligibility for consideration was other than the total customer cost test?

MR. SHALABY: A. The potential would be very different if we used, for example, the ratepayers

impact measures test. And maybe from now on I will call it the RIM test. I don't think I can rhyme that off too many times without stumbling. So the RIM test would result in which fewer success or much fewer programs being offered to the public.

And the reason for that is that you put a very restrictive requirement, and that is, the non-participating customer should not ever subsidize or suffer from the implementation of demand management if he chooses not to participate. That is a restrictive test and would almost surely result in a very minimal effort in demand management if that was the test that we used for screening.

And, in fact, the Ontario Legislative Committee of Energy, the Select Committee on Energy, recognized that restriction of the RIM test and recommended that Hydro not consider that test, and called it the "no loser test" at the time, and not consider it for screening and we followed that recommendation and we do not use that test for screening.

Q. And is the total customer cost test used by other utilities or in other jurisdictions for purposes of program screening?

A. Yes, it is. It is in common use in

several states in the United States. It is, in fact, the most important test in such jurisdictions as California, New York, Ohio and Massachusetts and it finds its way in many other jurisdictions as well.

It is sometimes called "the total resource test" or "the total societal cost test", different labels, same concept, same equations. So, the total customer cost test is equivalent to what you might hear mentioned as the total resource test or the total societal cost test.

Q. Now, is it a problem when you are looking at this test that in some of those jurisdictions, you have investor-owned utilities which, of course, is a somewhat different situation than Ontario Hydro?

A. It really is perhaps an added complication. It is not entirely a problem, but in evaluating demand management in an investor-owned utility, and those are the dominant motive delivering electricity in the United States. Something like 60 per cent or 70 per cent of the electricity is sold by investor-owned utilities.

The reason there is complication or an added dimension is that you have another player, and that is a shareholder. In the boxes that we showed, we

showed the customer. In Ontario we have the customer, the municipal utility and the distributing utility. In an investor-owned utility, there is also the shareholder. It would be an investor that owns the utility.

The impact on the shareholder is yet another dimension to worry about or to look at. Shareholders are typically interested in the net profits of the utility. And demand management programs can really erode the earnings of utilities and become a detriment to the investor.

And typically, utility regulatory commissions in the United States have looked for ways to motivate investor-owned utilities to invest in demand management. And again, typically, the ways to promote demand management is to find ways to split the benefits of demand management between the investors and the customers.

So, they give the utilities incentives. By promoting demand management, they give -- the regulatory agencies give the investor-owned utility incentive to promote demand management.

Now, that added dimension is really absent in Ontario and in that sense is not an impediment to aggressive pursuit of demand management

and that is, of course, because our shareholders are the same as our customers. The public ownership of Ontario Hydro removes that added dimension in considering demand management programs.

Q. Now, I have got a final few questions in this area and they focus a little bit on the fuel switching side.

Can you use the total customer cost test to evaluate a fuel switching demand management option as well as one that provides improvements in electricity efficiency?

A. Yes, you can. The total customer cost test can be extended to screen the cost effectiveness of switching. And by switching, we mean converting a house, for example, that uses baseboard electric heaters to become heated with natural gas. That is what we call "fuel switching options".

To conduct that test, to show whether conversion from baseboard heaters to natural gas heating is cost effective from the perspective of society in general, if you like, the information we would need is information on the costs of the natural gas system, if that is a conversion that we are going to.

So, in addition to knowing what the

savings in the electricity system would be, we would want to know what the costs will be of providing natural gas to heat that house.

Now, in Ontario Hydro, we are much more familiar with the costs of electricity supply and the savings in electricity supply. We are less familiar with the gas system and the incremental costs of gas system upstream and downstream and so on.

At this stage, what we are using as a proxy, as a first cut to give us an indication of what the incremental cost of gas is, we are using the price of natural gas in the market. So, that is a first attempt at determining whether a switch to natural gas is societally more cost effective than staying on electricity.

Q. And could you give us an example, please, of the application of the total customer cost test to a fuel switching option?

A. All right. To give that illustration, I would like to go to page 8 of Exhibit 260. And the information here is mostly included in Exhibit 257. Table 6 of that exhibit has some of this information. We are providing additional detail here to illustrate how fuel switching is evaluated.

If we look at the first line, it shows

that a conversion of -- the example we are looking at here is a one-storey house with a finished basement, has baseboard heaters and has water heating using electricity as well.

And if we assume that the water heater and the baseboard heaters have come to the end of their useful life - they are not brand-new or anything. They served the house for a number of years and are really due for replacement.

At that stage, continuing for 20 years to provide electricity as the source of heating and water heating would cost $14,150; that is, the costs of electric supply to provide those services to that particular house for 20 years.

Now, it is shown here as a benefit or avoided cost because we are saying, if you move on to natural gas, then the savings would be $14,150. So, that is a saving on the electricity system if you switch to natural gas.

The costs of converting to natural gas are shown in this table under two categories: The first one is entitled, "extra gas supply cost". That would be the price of natural gas for 20 years to supply the house, and that is $8,095.

The second category associated with gas

service is incremental equipment cost. And that here is dominated by putting ducts. A house that has baseboard heaters typically doesn't have ducts. There will be expense to do with ducting and providing air flow through the house.

Other costs in incremental equipment costs would be the furnace, the cost of the natural gas furnace. And if the there is any difference in the maintenance cost of a gas furnace versus an electric furnace, it will be captured in that category as well.

So, the sum of those two numbers, the costs of providing that service to that house for 20 years, is 12,650. The cost allocated to 20 years would become 12,650. And the benefit by moving off electricity is 14,150. So we see there is a net benefit of switching that house from electric and water heating to natural gas, space and water heating.

So, that is really the extension of the total customer cost test to a fuel substitution or a fuel switching, as we call it, that is the example, that is how it is done.

MR. B. CAMPBELL: All right. Now, Mr. Chairman, those are some of the concepts that we wanted to deal with in particular. I would now intend to turn to Mr. Burke to deal with the demand management

opportunities or potentials. And perhaps given the time though this would be the appropriate place for a morning break.

THE CHAIRMAN: All right.

Mr. Greenspoon, perhaps we will deal with your notion if it is convenient, or submission or whatever it is, at 2:30 when we come back from lunch.

In the meantime, could you talk to Ms. Formusa about what your problem is and see if you can resolve it?

MR. GREENSPOON: Sure.

THE CHAIRMAN: We are adjourned for 15 minutes.

---Recess at 11:32 a.m.

...

---On resuming at 11:51 a.m.

THE CHAIRMAN: Please be seated.

MR. B. CAMPBELL: Thank you Mr. Chairman.

Now, I'm told that the mikes have been switched into some different mode, whereby they are on unless they are turned off. So, I'm going to ask the witnesses if you would turn it on when you speak, and then once you have dropped your pearls of wisdom, you can turn it off again, and it will save -- this will help me no doubt because I keep forgetting to turn mine on as well. So, I think it would be slightly easier.

THE CHAIRMAN: This is demand management program, is it?

MR. B. CAMPBELL: Actually it is quite the reverse, because I am told they are on, unless you turn them off. So, it is the turning off that this panel is quite good at.

Q. Now, before these analogies get carried too far, I want to turn to the area of demand management opportunities. That is the potential that exists in the province for demand management. And I'm going to ask you to deal with this in the first instance, Mr. Burke, and start by outlining the demand management opportunities that Hydro analyzed for purposes of the preparation of the Demand/Supply Plan.

MR. BURKE: A. The demand management opportunities that Hydro considered in the Demand/Supply Planning report that was Exhibit 3, things that would reduce the basic load forecast, were electrical efficiency improvement, which I have a habit of abbreviating as EEI, and it is shown as EEI in the overhead; load shifting, which is shown as LS in this overhead, which is page 9 of Exhibit 260; and capacity interruptible loads.

Now, capacity interruptible loads aren't on this overhead, and that is because in the intervening time we have changed the name. They are now called discount demand service and are abbreviated as DDS. DDS is something that reduces the primary load on the way to obtaining the firm load, but it is the same thing. It is an interruptible load effort.

Now, as this overhead indicates, and as we discussed in Panel 1, the primary load is derived by subtracting the EEI, the load shifting, and what was known in Panel 1 as load displacement non-utility generation from the basic load to get the primary load. And the load displacement, the LD NUG abbreviation there will be discussed in Panel 5.

We are going to restrict ourselves to the EEI and the load shifting, but as you have gathered

from the discussion this morning, we will address the fuel switching possibilities that are brought about with the change that is pending in the Power Corporation Act. So, fuel switching is now included as one of the options to reduce basic load on the way to the primary load, and it is abbreviated FS in overhead No. 9.

Q. All right. Now what exhibits, if you could just outline the exhibits, please, that support your assessment of demand management opportunities?

A. Well, the analysis of demand management opportunities is summarized in Exhibit 25. That was entitled "Demand Management in the 1989 Demand/Supply Plan," and those estimates were based on the 1988 load forecast. An update to the EEI and the load shifting analysis was filed as Exhibit 76 in January of 1991, and that was entitled "The Net Load Impact Forecast of Demand Management Program," and in that document the residential sector EEI analysis was consistent with the 1990 load forecast.

While because of time constraints, the commercial and industrial results were derived actually using the 1989 load forecast data. This was just an unfortunate timing issue. However, the 1990 load forecast, as you may recall, was several per cent lower

than the 1989 forecast, so I would hazard that if anything, the projections in Exhibit 76 might be lowered slightly, were we able to use the 1990 data consistently throughout the piece.

It is Exhibit 76 that is going to form the basis of Hydro's evidence on demand management potential in the areas of electrical efficiency improvement and load shifting. However, with the introduction of fuel switching, the obtainable potential for EEI is better captured in Exhibit 258.

The estimates of fuel switching potential that we will be using are filed in Exhibit 257, and they are going to be presented here fairly completely to give you an idea of what this option is about.

Q. All right. Now, Hydro uses a family of terminology to describe the potential for energy efficiency improvements, which from now on I will adopt the terminology EEI for. I should say by the time we are finished we should save several dozen pages of transcript by doing this. And as I say, there is a family of terminology used to describe the potential for EEI.

Could you please explain these before we go any further in this discussion?

A. Page 10 of Exhibit 260 is actually an

overhead form from figure 37-3 of the Demand/Supply Plan. It has a hierarchy of potential EEI concepts spread out there. What I hope to do is clarify some of them for you and show you which ones are still in active use. Potential total EEI is the top box, and that is the amount of load reduction that would be possible by some year in the future. Usually in our studies that is the year 2000, when EEI technologies that pass the screen of the total customer cost test Mr. Shalaby was talking about are applied to the full range of eligible loads in Ontario.

Now, as you can see from the way the boxes are arranged, potential total EEI is composed of two elements, natural EEI and potential induced EEI, and these are estimated independently. Natural EEI is the efficiency improvement that results from normal market forces over standards legislated by governments. This continuing trend to improve efficiency is captured in the basic load forecast as we discussed in Panel 1.

Potential induced EEI is total impact by a specified year of the remaining economic induced EEI -- sorry, is the remaining EEI opportunities. That is the ones that would not occur naturally. These load reduction measures face one or more barriers to market penetration, and these must be overcome by Hydro or

perhaps the government before they are likely to be taken up by the customer.

To put this more concretely, potential induced EEI by the year 2000 is equivalent to 100 per cent take up of economic EEI opportunites that would not occur by themselves. Because estimates of induced EEI net out the naturally occurring portion of the efficiency gains, they are on a form that we can subtract them directly from the basic load forecast.

The way potential induced EEI is defined, it must be economically and technically feasible for those efficiency savings to be obtained in the time period that we have specified, again, typically in our analysis by the year 2000. And this is what allows the penetration rates, which are the next box down, to be applied directly to potential induced EEI, in segment, in order to derive the attainable induced EEI estimate.

The net load impact forecast for EEI, that is pretty well the words in the title of Exhibit 76, mean the same as attainable induced EEI.

Now, in Exhibit 76, the potential concept that is used throughout is the potential induced EEI. We rarely, in fact, use the potential total EEI, that top box, because our main interest is to see how the basic load forecast can be reduced by our programs.

There are a few other boxes on this overhead, and one of them is unidentified induced EEI. And this was an amount that was added to the attainable induced EEI in Exhibit 25, which was made in 1988, to make up the difference between the identified opportunities and the corporation's target of 2000 megawatts.

The way the estimates were prepared in 1990 for Exhibit 76, additional analysis has allowed us to account for the full 2000 megawatts, and so the unidentified portion has effectively disappeared. And for all practical purposes then in Exhibit 76, there is no distinction between attainable induced EEI and planned induced EEI.

Q. Now, do these concepts of potential induced and attainable induced generalize to the other demand management options, such as fuel switching?

A. Yes, they do.

Q. Following this framework, I think it makes sense then to begin with the estimates for potential induced demand management, and perhaps you could just briefly outline how the discussion of that potential induced demand management is going to be structured.

A. Yes, I'm going to review the

estimates for potential EEI and fuel switching, and then Mr. Shalaby is going to come back and outline the system opportunities for load shifting, and Mr. Harper will show how time of use rates have the opportunities to fully utilize that potential, and he will also discuss the opportunities for discount demand service or interruptible power.

Q. Now also, has the proposed removal of the statutory limitations on fuel switching made a difference to your analysis?

A. Yes. Now that we have introduced fuel switching as a demand management option, it is no longer possible to simply sum the potential or the attainable results, for that matter, of each of these measures, to arrive at a meaningful total demand management impact.

I think you can see this fairly directly, that if the potential to improve electrical load in an application is being measured in one place, and then you switch that load to gas, you are double counting. A concrete example would be that, talking about a new R2000 house and the savings that you would get from that, we'd be double counting at the same time and suggesting that that house be heated with gas. So, we would have to be careful in adding up the efficiency

opportunities and the fuel switching opportunities that we are not in fact counting the efficiency gains in houses that we have switched to gas, for instance. So that is an effect on electrical efficiency improvement.

There may also be an effect on load shifting. At the moment we are assuming that this is minor, and we are not pursuing it further in the discussion that we are going to have today.

When I first present the analysis of electrical efficiency improvement, I'm going to do it in the absence of fuel switching. Then I'm going to introduce the potential for fuel switching, and finally come back to describe the overlap between the two.

Q. All right. Well, starting into that then, I would like you to outline the major assumptions underlying Hydro's analysis of potential induced EEI.

A. I am going to talk about four principles that we have kept in mind in doing our analysis. The first one is that electrical efficiency improvement means providing the same or better quality of electrical energy service while using less electricity. This has application -- or implications for the cost of electrical efficiency improvement, and/or the rate at which it may feasibly be acquired. It is not just sort of a trite statement.

Secondly, Hydro estimates economic potential, not technical potential. And that is important, because when we apply the total customer cost test, it is better to be using reliable cost and energy savings data than simply speculating about the costs and savings of technologies.

What this does is affect how new technologies will fit into the determination of primary new load.

The third thing is that Hydro is interested in the estimate of potential load reduction that may be feasibly and economically available by critical dates that are important for Demand/Supply Planning.

...

[12:05 a.m.] Estimates based on instanteous replacement of the existing stock of equipment are inadequate in this context as many EEI measures are really only economic upon replacement and other constraints limit the rate at which savings can even potentially be obtained. And finally, in deriving induced potential, Hydro makes every effort to appropriately net out the impact of efficiency improvements that would have occurred anyway and are either implement or explicit in the basic load forecast. This permits the obtainable induced estimates to derive directly from the potential estimates, but it also will make our numbers look smaller than those in studies that look at savings relative to some base year or frozen efficiency level.

DR. CONNELL: Mr. Campbell, excuse me, I wonder if I could ask Mr. Burke to repeat his second point.

MR. B. CAMPBELL: We are going to come back and discuss each of these in turn. At this point he is going to give some more detail. So, perhaps when he gets to that point and he is moving on to the third, if your question remains outstanding, perhaps that would be an appropriate time to take it.

Q. Mr. Burke, as I say, I want to deal

with each of the implications in turn starting with the focus on electricity efficiency improvement without reduction in the quality of service, and could you explain, please, how potential induced EEI is impacted by this condition?

MR. BURKE: A. Well, with few exceptions, Hydro screens out measures that actually do less with less.

The intent of our programs are not to induce lifestyle changes. And, for instance, aesthetic qualities of the customer's house, or whatever, must be maintained when they adopt an EEI measure. If we are going to put insulation on their exterior walls, for instance, we can't just leave the house with a bunch of insulation on the outside; it has to be clad in some way, perhaps aluminum siding has to be put on, that sort of thing.

If we are going to put insulation into basements, it should be covered with plasterboard. If we are installing new lighting systems in offices we have to make sure that tasks are still properly lit and that may, in fact, require work on the ceilings and so on, that really comes more in the line of a renovation than simply a retrofit measure for efficiency improvement.

All these aesthetic considerations that affect the quality of the services the customer was enjoying are expensive and limit some of the measures that may be installed to a time when renovation was going to occur anyway.

Home renovation only occurs, in our estimates, about in 2 to 4 per cent of the housing stock every year.

So, there are a variety of measures that are potentially there, but because we are concerned about the aesthetics of what we are doing, we can only aquire these at a limited annual rate, taking into account the economics that change when we are in a renovation state.

Furthermore, we have assumed that appliance efficiency gains will occur without eliminating the services customers have been demanding. The trend toward larger sizes of refrigerators is assumed to continue while at the same time they become more efficient.

Hydro assumes that Ontarians do not wish to become like Europeans who shop for food daily and that tends to lead to refrigerators in Europe that are roughly one-third the size of the North American model.

So, again we are not trying to develop

efficiency improvement through lifestyle change.

Q. Now, your second point concerned a distinction between economic and technical potential for EEI, and I guess, briefly, I would ask you to explain why Hydro does not estimate technical potential for EEI in doing this analysis?

A. There are many interpretations of the distinction between economic potential and technical potential. I might begin by saying that some things that may be technically possibly are just simply not economic.

The operational consideration for Hydro is that some versions of techical potential permit inclusion of technologies that have not been commercially applied and demonstrated to be reliable,, As a result, their incremental costs and the energy saving performance of those technologies remain speculative.

Hydro - and I believe this is the general practice among electricity utilities in the states and the public service commissions that regulate them - base EEI estimates and integrated resource plans for that matter on the most efficient technologies with commercial operating experience.

Were you to apply the term "technical

potential" to proven technologies, then it would be a logical extension of what we are doing with economic potential, but the extent to which technical potential would exceed our economic potential would simply be the extent to which there were proven technologies that had avoided costs higher than the avoided cost that Hydro is using for screening in the total customer cost test.

But in practice, we find that there are few options for which we have reliable cost and performance data that do not already pass the total customer cost test, and most of these turn out actually to be in thermal envelope upgrade situations that may turn out to be redundant with fuel switching anyway.

Q. If you know how much an energy efficient improvement opportunity costs and how it performs in commercial application, how do your forecasts accommodate the inevitable improvements in technology over a long-term planning period?

A. Maybe before I answer that question, I should point out that some of the characteristics of the distinction between economic and technical potential that I have been talking about are addressed in overhead 11, Exhibit 260.

It's reasonable to expect that the costs of some EEI technologies that are already relatively

expensive today, will fall. And that either because of economies of scale as market share rises or because there actually is a technical breakthrough, the cost of these technologies will come down over time and effectively be taken up by customers on what might be call a natural basis, essentially become part of the basic load.

At the same time we can expect new technologies to emerge from the labs that will be even more efficient than the technologies that we have been working with to date. But they probably will start at an initial cost that is not yet attractive in the marketplace, and so they would be in the category of a technology that would not naturally be adopted in the marketplace without some sort of incentive.

Hydro's estimate of potential induced EEI essentially assumes that these two trends in technology will be offsetting. So, essentially what we are saying is the snapshot of potential EEI that we take today may be realistic in terms of the megawatts of savings potential that we are calculating, but when we look back on this 10 years from now, the precise technologies that we have used may not turn out to be the ones that are used in practice. So, the estimates today may be correct in quantitative terms but as time

goes on, the technologies themselves will evolve and some new ones will enter our induced area and some of the ones that we considered will require programs may, in fact, occur naturally.

Q. Now, I am going to move on to the third principle.

Dr. Connell, I don't know whether that addressed your question, but if not...

DR. CONNELL: I haven't got that new technology here, I am afraid. Nothing happens when I push the button.

I think my problem might be helped if Mr. Burke could give us a particular illustration of technological versus the economic.

MR. BURKE: For instance, there are technologies for refrigerator panels, vacuum panels for refrigerators that are in the labs at this point. It's not clear what their cost will be in terms of when they become available for commercial production, or even whether that particular approach to improving the insulation values of refrigerators will, in fact, reach commercial production. And so one could develop an estimate of potential based on the additional savings associated with that technology, but we wouldn't have a way of screening it because we really wouldn't know

what the incremental cost was against the incremental savings. And we have chosen to leave technologies for which we would have to speculate about the cost and savings out of our potential EEI estimate.

And as I say, that seems to be the practice pretty well everywhere, that people are not basing their plans on speculations about what future technology will bring, but they are really concentrating on the technologies that we know about today and have had some experience with, maybe not a lot but some.

THE CHAIRMAN: Is that the reason why you no longer have unidentified induced EEI?

MR. BURKE: There are a range of new technologies that we have included in our estimates. I will be getting to that, to some of the factors that have changed between 1988 and 1990 in estimating potential. And yes, certainly some of the measures that we did not include in 1988 we can include now. One in particular is the electronic ballast that accompanies the T8 lamp system. We felt that it had undesirable characteristics from what our technical people were telling us, that it introduced harmonics into the power systems of the buildings that it was operating in and so we shouldn't be recommending it for

use by customers. That problem now seems to have been solved, and so the electronic ballast is used in our estimates of potential induced EEI, and has contributed to increasing the estimate for the commercial sector.

Is that helpful?

MR. B. CAMPBELL: Q. If I can turn you then, Mr. Burke, to your third principle, it related to taking the replacement rate of equipment into account when estimating the economic potential for EEI available by a certain date for planning purposes. Why is it that electrical efficiency improvement for most equipment is only economic for new purchases or at the time of replacement?

MR. BURKE: A. When the total customer cost test is used to screen EEI, or any other option for that matter, as Mr. Shalaby pointed out, it's the incremental cost or the extra cost of the more efficient measure relative to the base case technology that's relevant.

Overhead 12 of Exhibit 260 is an example of the application of the total customer cost test to a situation where you look at purely the incremental cost of an efficiency gain for refrigerators, that's the $200 column, versus the case where you consider replacing the whole refrigerator which we are saying

here would cost $1200, including the extra cost of upgrading to a high efficiency model.

This is an example, and for simplicity, we are suggesting that half the energy consumed by this refrigerator can be saved for $200, so the final consumption is 600 kilowatthours a year, and the extra $200 essentially buys you a flow for 20 years of 600 kilowatthours per year savings.

The avoided costs of electricity for refrigerators is estimated to be 4.1 cents, and on the very bottom row, under the upon replacement column, the cost of saved energy is 2.7 cents a kilowatthour hour. So, this passes the total customer cost test and it is economic to encourage the purchase of a more efficient refrigerator upon replacement.

However, if we were to try to offer to buy the customer a complete new refrigerator, that is essentially go into someone's home and say, "I will take your current fridge away, I'll give you a new one," would that be economic? And what this example shows is that when you have to pay for the full $1200 against the 600 kilowatthours per year savings, it works out to 16 cents a kilowatthour and it is clearly uneconomic to do this.

So, it matters that you are at the point

of replacement when you are offering these sorts of programs and it affects the potential that you can get as a result.

In fact, there are only a few technologies that are so efficient and so economic that their savings do justify premature replacement, and I would hazard that most of these are already being picked up by the customer; we wouldn't have to offer any sort of program to bring those about.

Q. Now, does that approach have implications for the rate at which EEI can be economically acquired in the province?

A. Yes, it does. The real world implication is that it is not cost effective to retire a refrigerator early to replace it with a more efficient one. It's only when the customer is about to purchase a new refrigerator anyway that it is economic to intervene and to try to influence the choice in favour of the higher efficiency model.

A significant consequence of this which generalizes to pretty well all electrical equipment purchases, is that the eligible market for more efficient technology in any given year is only composed of the purchases associated with new additions to stock and the replacement of equipment at the end of its

physical life.

What that means is that for the year 2000, technologies with a life less than 10 years long, all of that is likely to be eligible for replacement by the year 2000 because it's 10 years from now.

Equipment who physical life exceeds 10 years is not all eligible for replacement by the ~~year~~ year 2000, and so will only capture a portion of that.

The potential induced EEI estimates that we prepare captures this effect.

Q. And how do you deal with practical considerations, for instance, such as the ability of trained people to undertake measures, let's use a different example such as thermal envelope upgrades, the tradesmen that are required to do those kinds of things, how do you deal with that kind of situation?

A. We do try to take it into account. Using of the thermal envelope upgrades as an example, measures to improve the thermal integrity of a building, either a residential or commercial, can usually be undertaken at almost any time prior to the demolition of the building, and there is no particular time that is more appropriate than any other, although you hope it's not just before the building is about to be torn down. But in practice, we couldn't go and take

advantage of all those measures in a very short period of time.

We would have to have sufficient infrastructure in place to be able to install all those weatherization measures, and that's because when we have done our analysis using the total customer cost tests, our installation costs reflect normal market prices. And if we try to retrofit all homes, for instance, in Ontario in a period of two or three years, we would definitely create all kinds of bottlenecks in the market and that would inflate prices. You would have to be pretty careful in the way you planned for a program such as that, to be able to avoid that sort of price impact, and I am not even sure it is possible.

What we do assume is that over a period of 10 years it is feasible to retrofit thermal envelopes and undertake all the economic measures by the year 2000 in both the residential and the commercial sector.

So, my point here is simply that you can't do it in one or two years, it does take at least 10, and we have suggested that we think it is possible in about 10 years.

...

[12:24 p.m.] To sum up the replacement end of equipment as well as these thermal envelope situations, the potential for efficiency improvement in the year 2000 or by the year 2000 is the maximum economic efficiency gain which we can apply to the eligible stock. And in the case of electrical equipment, that means to all new and replacement purchases anticipated between 1991 and 2000 and in the case of building envelopes, we are saying the entire existing stock.

Q. Now, are there other studies around of this kind of topic that take a somewhat different approach?

A. Yes, there are. Many studies, in fact, consider the entire existing stock or even the projected stock eligible for improvement instantaneously, even though it would neither be economic nor feasible to do this.

These sorts of results are interesting, but they do not lend themselves to direct translation from potential to attainable. And that is what we are trying to do in the way we address potential induced EEI.

We are going to return to this issue of how our estimates compare to those developed by others methodologically later on in the presentation.

Q. All right. Now, your fourth principle was to net out natural efficiency gains and perhaps you would remind us how you do that.

A. In estimating potential that may be induced by a particular year in the future, Hydro is interested in knowing how much energy would be saved relative to its base case of forecast energy demand.

An efficient equipment purchased today may save 30 per cent of the energy of the equipment it replaces. It may only save 20 per cent of the energy relative to a new item purchased today. And by the year 2000, it may save only 10 per cent of the sort of equipment item that it could purchase by that point in time. So, it matters very much when the equipment was purchased how much you can credit the energy savings.

Although our approachs differ by sector, we have attempted to net out the impact of those underlying natural trends in efficiency gain whether they are going to rise through market forces or through standards.

In some applications, what we have called natural efficiency gain in the basic load forecast may actually involve take-up of a certain proportion of the high efficiency technology that we have included separately in our potential estimates. This is the

case, for instance, for R2000 houses.

Roughly, 2 per cent of the housing stock in Ontario is R2000 or so. We wouldn't expect that to increase in share very much over time unless our program would make a big difference to the acceptability of R2000 houses. But you couldn't say that no R2000 houses are going to be built in Ontario. And so implicit in the basic load forecast is a certain number of these.

From a program point of view, these would become free riders; essentially, people who would have done it anyway, and they might benefit from incentives. But from the point of view of the analysis of potential induced EEI, they are part of the natural efficiency gain that is embedded in the basic load forecast.

There are always going to be customers who adopt extremely efficient technologies before they are economically attractive to the vast majority of customers, but there is a flip side to that; there will always be customers who never adopt even the most minimally cost effective measures. And that is -- the average of that is what is captured in the basic load forecast.

Q. All right. I want to turn now from that discussion to the estimates of potential

themselves.

And am I correct that that analysis is done on an end-use sector basis?

A. Yes. We do it on a sectoral basis because the characteristics of electricity demand in each sector and the data that we have available for each sector differ and dictate slightly different approaches. So, I am going to go through analysis for the commercial, the industrial and residential sectors.

Q. All right. And perhaps you could start with the sector that is seen as having the most potential identified; that is, the commercial sector.

I am going to ask that you first give the panel a brief overview of the load characteristics of that sector that are pertinent to an analysis of energy or electrical energy improvements.

A. The commercial sector is a big sector. It constitutes about 34 per cent of electricity demand in Ontario. About 14 per cent is non-building related, things like streetlighting, public water works and so on. And the rest is used in buildings with quite varying characteristics. I am going to concentrate on the building-related demand for the purpose of this presentation.

Our end-use forecast which we presented

in Panel 1 analyses 12 building types. They are listed in overhead 13 of Exhibit 260. And in the left-hand column under COMMEND are the 12 building types that we have prepared load forecasts for.

However, we find that in doing analysis of electrical efficiency improvements, the economics or practicality of efficiency improvement measures can vary significantly even within these building types. And we further subdivided them, as you can see on the right-hand side, so that the EEI analysis has a total of 18 building types for existing buildings.

Now, when we go about analyzing the buildings, the unit of analysis is still the square feet of floorspace, the same that we were using for projecting demand.

Ontario Hydro estimates that there are currently 2-1/2 billion square feet of floor space in the commercial sector and that by the year 2000, we are going to have 22 per cent more or 3.1-billion square feet of floor space in the commercial sector. At that time, we expect electricity demand to be about 45 per cent higher than it is today, again in the commercial sector, building related.

Electricity use per square foot is about 16 kilowatthours per year, although the electricity

intensities range from 7 or 8 kilowatthours per square foot per year for buildings like churches, warehouses and apartments, right up to nearly 30 kilowatthours per square foot per year in offices, retail establishments and accommodation. Those numbers are contained in overhead 14 of Exhibit 260.

In the next overhead, overhead 15, there is a summary of the shares of floor space and electricity use for the various types of commercial buildings. You can see that one third of the floor space is actually in apartment buildings. Offices are next at 15 per cent and retail buildings occupy 10 per cent of the floorspace in Ontario.

But that is not the same as the rate at which they use electricity. From that perspective, offices are the major opportunity for demand management because they consume 28 per cent of electricity use. The retail sector is 19 per cent of electricity use and the multi-residential sector is 16 per cent of electricity use.

In overhead 16 of Exhibit 260, I have shown the end-use composition of the commercial sector for 1989. Total demand is about 40 terawatthours and lighting, indoor lighting, consumes about 30 per cent of that or about 12 terawatthours. That is about 9 per

cent of the total electricity demand in Ontario.

Space cooling is the next largest end use at 6 terawatthours or 16 per cent of building-related load and office equipment and ventilation each consume about 4-1/2 terawatthours each, roughly 11 per cent.

Space heating is the last of the major end-uses at 3.6 terawatthours or 9 per cent of building related load.

Q. All right. Now, against that background, how is potential EEI determined for this commercial sector?

A. The consultant study which underpins the commercial analysis was filed in response to Interrogatory 4.7.4.

MR. B. CAMPBELL: And that would be the third item to add then to Exhibit 261?

---EXHIBIT NO. 261.3: Interrogatory No. 4.7.4.

MR. BURKE: That interrogatory response has a very large number of documents that were filed under its number, so I don't know what you are going to do with that exhibit, but anyway ...

MR. B. CAMPBELL: Q. But we know which one you are referring to and that is the commercial building analysis.

MR. BURKE: A. That's right. In that

study, 11 of the 18 building types that I listed a few minutes ago were used to -- for 11 of the 18 of those building types, the consultant created typical energy use profiles, and this is an example of one of them. It is for a small office building, a building of roughly 40,000 square feet. And what the consultant did was to characterize the building envelope, the electrical system, the mechanical systems and the electrical end-use usage in that building type.

Now, I don't really expect to you absorb these details. I just wanted to give you an impression that in putting these profiles together, a fairly detailed look at what constituted a commercial building was taken and, in fact, the description in the overhead is a summary description compared to what you will find either in Exhibit 25 or that consultant study which is sourced at the bottom of the slide.

The electrical efficiency improvement possibilities for each of these typical buildings were analysed on an end-use basis. We started with lighting, taking into account the impact of lighting changes on air-conditioning load. And then the motor loads were analysed for spacing that affect the space conditioning, whether it is air-conditioning or heating. And finally, we looked at a variety of

miscellaneous uses and space heating.

I should say electric space heating doesn't come up as much in the sector as one might expect because it is really a small share of commercial sector load; 9 per cent from that pie chart I showed you earlier.

And as it turns out, 35 per cent of electric space heating in the commercial sector is in apartment buildings and some other segments of the market have a fairly negligible share of electric space heating.

Another load that doesn't figure in our analysis very much is the air-conditioning load. It was 15 per cent of building-related load, but as it has very little impact at the time of winter peak it hasn't been included in potential EEI to date, except in large office buildings which do require cooling year round.

So, the building profiles were used to develop packages of efficiency improving technologies that were appropriate for that building. In doing so, we have been able to capture many of the synergies between lighting and heat, cooling and ventilation systems and reflected these in the electricity savings that we have used. And it is those estimates after the synergies has been taken into account that we have used

when we have been screening the individual measures in the buildings against their incremental costs. So, it is the imputed electricity savings after the synergies have been taken into account against the incremental cost of the measures.

Also, we have taken into account the fact that the load shapes, the saved energy, should be appropriate for each of the building types because, in fact, commercial buildings differ quite significantly in the amount of use they have. We had an example of that already with the religious buildings that Mr. Shalaby was talking about and the reason that particular test failed was because of the hours of use. So, that is why some of the results differ for each building type.

Q. Now, against that background, can you give us an example of the measures that would be applied in a typical building when you are conducting this kind of analysis?

A. Well, in overhead 18 of Exhibit 260, I have actually given a complete technology list that we used for the commercial sector in Exhibit 76.

But looking through, down the list at what technologies would actually show up in the example I have been using so far, that of a typical small

office building, that particular building package consisted of lighting redesign, which includes the removal - in part, the removal of unnecessary light fixtures, a T8 fluorescent lamp system with an electronic ballast, some compact fluorescent lamps; under the motor related, the air and water balancing of the fan and pump systems respectively, energy-efficient motors, a building automation system, window film and ground source heat pumps as appropriate for space heating measures.

So, in fact, one of the reasons I picked the small office building example is that it is a case where a wide variety of measures can be applied.

Q. And does that list differ from the measures that were explored in Exhibit 25, the earlier exhibit?

...

[12:38 p.m.] A. Yes, it does, and the asterisks on the technologies denote the new technologies that have been added since Exhibit 25. That pertains to the Chairman's question a few minutes ago.

So, we have added, since Exhibit 25, T8 fluorescent lamp systems with electronic ballasts. The T8 lamps themselves were included in Exhibit 25. It is the electronic ballast in combination with the lamp that is different. And there is a synergy between the ballast and the lamp that is important to capture.

Also, the space heating measures, ground source heat pumps are not a now technology, but we had not particularly applied them to the commercial sector, because space heating load at the time was considered a fairly small load from the point of view of the commercial sector.

In fact, in the latter half of the '80s, space heating shares in the incremental market of the commercial sector grew phenominally, and so we felt it much more important to take into account the efficiency improvement potential for electric space heating in the commercial sector.

I think we discussed the penetration of electric space heating in the commercial sector in Panel 1. It is not really a price phenomenon. People

seem to be using it for other design reasons.

Q. Now you have discussed the T8 lamp system, why it wasn't included in the analysis of potential done for the D/SP. I think you have dealt with that. And I'd like you to turn to the difference that this change in the application of the T8 lighting systems made to the potential for lighting savings in the commercial sector, which Hydro has estimated.

A. Yes, in overhead 19 you get a bit of a picture of what Mr. Shalaby was describing earlier when he gave his example for T8 lamps. The 32 watt T8 lamp, with the electronic ballast, really is now the system we prefer to retrofit for the purpose of EEI programing in existing buildings, as well as in new buildings.

The T8 is simply a one-inch diameter light, tube, and the 40 watt is an inch-and-a-half diameter, and they have different rated wattages. But the combination of the lighting supplied by the lamp, which is given under the column "Initial Lumens," and the "Colour Rendering," which is rated for the standard 40 watt in the top row and the T8 in the bottom, mean that it is considered that the T8 offers better lighting quality than a standard 40 watt lamp. Not as many lumens but better colour rendering, and the

combination is considered to be a superior lighting system.

So, that system, a T8 versus a standard 40 watt, when we are talking about two lamps and ballast, saves 42 per cent of the electricity consumed by a standard 40 watt fluorescent tube, again with the core and coil ballast.

The advantage that the T8 system has, from the point of view of retrofitting, is that it occupies the same physical space as the standard fixture, but because it has a dedicated ballast, it is not possible to revert from the 40 watt system to a T8 system without, in fact, replacing the whole system. There is a dedicated ballast. And --

Q. I think you got that backwards.

A. Sorry, not possible to revert from a T8 to a 40 watt system. Did I say that backwards? Sorry. So, the permanence of the savings from our perspective is quite valuable.

Simply fitting energy saving tubes into the same fixture would allow the customer to go back to a 40 watt bulb, if they so chose later on.

Q. All right. Now does this mean that, picking up on this 42 per cent figure, does this mean that you, in all cases, credit existing buildings with

42 per cent savings where T8s are used?

A. Well, given the way we go about doing our net impact work, not quite. There is an alternative to T8 systems that's becoming increasingly popular throughout North America, and that is the middle bulb on this overhead, which is a 34 watt energy saving tube. It doesn't produce quite as much light, as you can see, as the standard 40 watt bulb and standard 40 watt lamp, and for that reason it really should only be put into a commercial space that is overlit.

However, it is so low cost that when we were putting the basic load forecast together, we assumed that a savings equivalent to a universal shift from the 40 watt tube to the 34 watt tube would actually occur by the year 2000. So, from the point of view of net savings with the T8 system, they have been reduced from 42 per cent to 33 per cent in each application in existing buildings. Although, as I just said, we do prefer to see the T8's, because they are not reversible, whereas the 34 watt energy saving bulb is completely reversible.

Q. So, this is an example where depending on the base you use, the amount of savings you get differ?

A. Absolutely.

Q. Now, what are the total savings then attributed to T8 systems in the commercial sector?

A. Well, there are approximately 85-million fluorescent tubes in use in Ontario today. And we have assumed essentially that all of them will be replaced by T8 systems, with a net saving of 33 per cent. And that cumulates to two terawatthours by the year 2000. In addition, we expect new buildings to use the T8 system, and that yields savings of about 1.1 terawatthours.

Q. What is the total saving attributed to lighting system improvements then, in Hydro's analysis?

A. Well, in addition to the T8 system, the main other lighting measures, or what was termed in my list lighting redesign and automatic lighting control systems. And when those measures are combined with the T8 system, in an application where all three are eligible, the savings rates can be as high as 45 to 55 per cent of the lighting use in that building.

But on average across the sector, lighting load reduction averages 33 per cent. And the reason the average is brought down is that there are some segments of the commercial sector where there is

much less or lower eligibility for lighting efficiency gains, and these are particularly the apartment sector and the retail sector.

Q. All right, given that then, what is the total potential induced EEI for the commercial sector?

A. The total induced potential is 15 terawatthours or about 3000 megawatts in the year 2000. This works out to 21 per cent of building-related load in that year.

In the example I have been following through for small office buildings, the result is 14 per cent, but actually that turns out to be relatively modest. Some of the buildings save well over 20 per cent.

That information is contained in Exhibit 20 of -- sorry, page 20 of Exhibit 260. And similarly in the next overhead, overhead 21 of Exhibit 260, I have illustrated where the potential induced savings may come from. Not surprisingly, the office sector is the largest segment of the market, yielding 30 per cent of the 3000 megawatts. The retail sector is next at 15 per cent. And apartments at 14 per cent of the 3000 megawatts.

You can see from the hash marks that

roughly one-quarter of the savings will take place in new buildings and three-quarters in existing buildings.

Q. All right, and how much does the commercial sector EEI cost?

A. Overhead 22 of Exhibit 260 is what Hydro calls a load reduction curve, and it plots the life cycle cost of measures on the horizontal axis against a vertical axis, which is the number of 16 hour peak megawatts. And you can see from this plot that the life cycle unit energy cost of measures of these building packages range from two cents a kilowatthour for existing apartments, up to about four and a half cents a kilowatthour for new office buildings.

The reason it is lowest in existing apartments is that this is a classic case where the landlord and the tenant have split incentives for improving efficiency, and very little in some cases has been done to improve efficiency in the use of electricity, so a lot can be done relatively cheaply.

Whereas, in the case of new offices, they probably are the showcase of where architects are currently incorporating more efficient technologies, naturally, and so to make an even more efficient office requires additional, more expensive technology.

We did not have technologies for each,

sort of technology by technology load reduction curves for this sector, because the analysis was done for 11 of the 18 typical buildings and generalized to the remainder. So, we couldn't really plot the entire savings by technology. But for those buildings for which we do have specific technology costs, they range from a low of .2 cents a kilowatthour, right up to the avoided cost, which depending on the application, ranges from 4.1 cents to 6.6 cents a kilowatthour.

MR. B. CAMPBELL: Now, Mr. Chairman, we are about to turn to discuss the industrial sector potential, and perhaps rather than doing five or ten minutes of that, this might be a good time to take a lunch break.

THE CHAIRMAN: Why don't we do that? We will come back at 2:15.

---Luncheon recess at 12:50 p.m.

...

---On resuming at 2:15 p.m.

THE CHAIRMAN: Be seated, please. We are going to deal with Mr. Greenspoon first.

MR. GREENSPOON: Mr. Chairman, as I wanted to do earlier, I wanted to indicate that we have three unanswered interrogatories to Panel 4, one of which I understand was answered yesterday and Mrs. Formusa just gave me the answer now, two of which remain unanswered and Mrs. Formusa undertakes to have those for me next week.

As well, I was served with a number of interrogatory answers last week, and also served with the fuel switching paper which has been made an exhibit today.

As I have said already to the panel, demand management to Northwatch is the alternative to the undertaking. It's the most important panel to us in this hearing.

I don't have instructions from my client to ask for an adjournment, I didn't have this morning, and I am not asking for an adjournment, I just wish to put on the record those facts.

THE CHAIRMAN: Thank you.

MR. B. CAMPBELL: Perhaps I should just put on the record, Mr. Chairman, that there are a few

outstanding interrogatories and that does not arise from any lack of effort on Hydro's part, let me assure you. We have worked hard and the people involved in preparing answers have worked extraordinary hard, but the volume has just been enormous. They have done the very best they possibly could do.

Now, with that fact on the record, I think, Mr. Chairman, I would like to pick up, if I could, turning to the industrial sector potential.

THE CHAIRMAN: Thank you.

MR. B. CAMBPELL: Q. Mr. Burke, I am going to ask you to again start by characterizing this sector, the characteristics of this sector from the perspective of estimating EEI potential.

MR. BURKE: A. Of the three sectors I am going to discuss, the industrial sector is the most diverse.

Electricity use differs significantly both within and between industries. Many applications are site-specific and as a result this sector doesn't really lend itself to constructing typical plants in an analagous way to the way I had typical buildings for the commercial sector before. So, as a result the usual approach taken by analysts is to focus on equipment types. This is equipment such as motors, or

to talk about specific technologies substitutions where these are known.

Hydro's potential EEI is estimated assuming that production continues using the same industrial processes that we use today, but making each equipment type more efficient.

Now, as indicated in Exhibit 76, this is somewhat restrictive, and Hydro is aware that it would be useful to undertake further study of the potential for process changes that reduce electricity use in Ontario industries and we hope to do these soon.

Q. How then did Hydro estimate EEI potential for this sector?

A. Hydro's estimate of potential EEI in the industrial sector in Exhibit 76 is based on the results of consultant studies which were supplied also in Interrogatory 4.7.4, which address six manufacturing industries and the mining industry, and these are listed in overhead 23 of Exhibit 260.

THE CHAIRMAN: I am not quite certain, but has 4.7.4 already been referred to?

MR. B. CAMPBELL: Yes, it was No. 3 in Exhibit 261.

THE CHAIRMAN: Thank you.

MR. BURKE: These particular industries

here account for 80 per cent of industrial sector load.

MR. CAMPBELL: Q. It might help again to remind the panel about the load profile of the industrial sector?

MR. BURKE: A. The industrial sector consumes roughly the same amount of energy as the commercial sector, about 35 per cent of provincial electric use. However, it's load factor is above the system average, so it represents a slightly smaller proportion of system peak, about 30 per cent of system peak, and we estimate about 7200 megawatts in 1989.

By the year 2000, industrial load is expected to grow about 30 per cent, to about 9,500 megawatts.

Now, the largest consumers of industrial electricity use are shown in the pie chart in overhead 24 of Exhibit 260, and this pie chart shows that the pulp and paper industry is the largest single consumer, consuming 18 per cent, followed by mining and chemicals at 14 per cent each, and the iron and steel industry consuming 13 per cent of electricity in the Ontario industrial sector. The total identified here is 59 per cent and the other industries make up 41 per cent.

The major end-use applications of electricity that constitute the focus of the EEI

analysis are shown in overhead 25 of Exhibit 260, and that indicates the mode of power is 76 per cent of the end-use in the industrial sector, process heat is 11 per cent, lighting and other make up 8 per cent, and electrolysis about 5 per cent of industrial electricity use.

Q. Perhaps you could explain what were the major technologies examined to estimate industrial potential EEI?

A. Well, the electrical efficiency improvement technologies are listed on this overhead number 26 of Exhibit 260, and they are similar for each of the manufacturing industries; that is, for each industry we looked at motor-related, lighting, energy recovery and energy management systems, and also for each industry there were some specific measures. I won't go through the entire list but it's described in Exhibit 76.

Also, for the mining industry itself, that industry was handled quite separately because there are quite a number of technologies there that are unique to that industry such as hydraulic drilling and agitater replacement and so on, and the complete list of technologies we examined for that industry is given in Exhibit 76 as well on page 51 if you are interested.

It's worth noting that the energy efficient motors themselves only save 2 to 6 per cent of motor load. Sometimes people have this impression that because such a large proportion of industrial load is made up by motor load, that surely there must be a huge potential. Well, the potential is not in the motors themselves.

Hydro's resource processing industry also happens to work on a fairly large scale and the motors that it has are also very large and large motors tend to be very efficient.

So, in fact, the total potential identified for high efficiency motors per se for Ontario is about 60 megawatts.

The major savings are really in the variable speed drive component. Variable speed drives are devices which allow motor loads to track the variations in process requirements, in particular if you are using pumps, fans or compressors this can be useful. And in these applications, adjustable or variable speed drive motor may save 25 and 50 per cent of motor load.

The total savings we have identified for Ontario are about 210 megawatts.

Finally, in the existing uses, fans,

pumps and compressors, we have looked at those to see how they could optimize themselves and identified 35 megawatts of potential.

So, the total of motor-related technologies that contribute to potential induced EEI is about 300 megawatts in Ontario. That's about 60 per cent of the portion that we have identified specifically in the industrial sector.

Light is the second largest category of savings and it contributes 60 megawatts or 12 per cent of identified potential, and the remaining 28 per cent are from a variety of industry specific applications.

Q. Now, which industries do your analyses indicate have the most potential for EEI?

A. Well, as page 28 of Exhibit 260 indicates, the biggest potential, not surprisingly, exists in the largest industries, and the chemical industry actually tops the list contributing about 20 per cent, mining is next at 14 and paper next at about 13 per cent, of the 520 megawatts of potential for which we can put a particular technology name on the saving.

Q. And what then is the total for this sector?

A. Well, the total potential induced is

the 520 megawatts for which we have specific applications, and also in Exhibit 76 we have included an extra 380 megawatts for technologies and applications. We have not specified the particular technology that would be applied. So, that brings the potential that we are counting on to about 900 megawatts, or 10 per cent of the year 2000 industrial load.

Q. And what is the cost of the measures included in the industrial potential?

A. Page 29 of Exhibit 260 is another one of these load reduction curves, and in it you see that the industrial measures are quite low cost. Most of the measures have cost below 2 cents a kilowatthour and there are only a few measures that we have identified with costs in excess of 2 cents a kilowatthour.

Now, despite these low lifecycle costs, the technologies that we have identified would not be attractive to industry to install naturally in the particular applications that we have credited to the potential induced numbers.

Now, the absence of higher cost measures in this load reduction curve may be because the more costly measures have yet to be specified because they are process specific and might involve design changes

which went beyond the scope of the studies that we have undertaken to date.

Q. What is it about the nature of these measures with low lifecycle costs that prevent them from being adopted naturally by industry in applications?

A. Well, on a lifecycle basis and some of this equipment may last 20 years, the payback to industry may still exceed the two or three years that typically is a maximum for industry.

So, while we analyze things on a lifecycle basis, and it may have low cost on that basis, when you are dealing with paybacks of one to three years, which I guess is the typical range for industry, it just may not make it from the industrial point of view.

Q. All right. I would like to turn then to the residential sector and perhaps start by reminding the panel how the residential sector is defined.

A. Yes. The residential sector is defined in the same way that we defined it for load forecasting purposes in Panel 1. It includes only single family dwellings. Dwellings with five or more units form the multi-residential segment of the

commercial sector.

So, the typical dwelling types we are looking at here are single-detached and single-attached houses, and single-attached ones are things like semis or rows or duplexes.

Q. All right. And perhaps again you could give us a brief profile of the electricity using characteristics of the sector as a whole?

A. Certainly. There are currently 2.7-million households in Ontario, and this is expected to grow about 15 per cent, to 3.1-million, by the year 2000.

Total sector load is about 41 terawatthours and that's about 30 per cent of the total Ontario consumption.

In this sector the load factor is well below the system average and that means -- it's about 50 per cent, and that means that peak load is actually a higher proportion of system peak. It works out to 9,000 megawatts, or 38 per cent of system peak.

Over this decade we expect the residential demand to grow about 18 per cent, that's on the basic load forecast.

Electricity use of household averages about 15,200 kilowatthours per years, so this really

isn't a very meaningful number by itself because the amount people use depends a lot on whether they have electric space heating or electric water heating. So, I am going to the look first at space heating.

There are about 480,000 all-electric houses in Ontario today that use electric resistance technology for heating. There is an additional nearly 100,000 houses that use heat pumps to meet all or part of their space heating requirements. Now, some of these heat pumps are backed up by other fuels, these are typically air source heat pumps, and they may, at the coldest time of the winter, meet their demand through the use of fossil fuels, or some use electric resistance elements.

For the purpose of analysis we did in Exhibit 76, a figure of 500,000 all-electric houses was used, which combines the pure resistance electric space heated houses with the resistance backed heat pump houses, and frankly was chosen to be a round number. Probably it's slightly larger than that.

...

[2:33 p.m.] By the year 2000, an additional 140,000 all-electric houses are forecast in the basic load forecast. Resistance heating, whether it is baseboard or central furnace, currently consumes about 16,000 kilowatthours per year and has a diversified demand coincident with the 16-hour peak of about 7 kilowatts perfect house.

This is a case where the concept of diversified demand that Mr. Shalaby was talking about earlier is quite important because the connected load per house is about 15 kilowatts, but the way the resistance elements in the heaters cycle, not all of that is on the system at any one time. So, 7 kilowatts is what the diversified demand is and that is the number we are using when we look at savings. We don't take the savings relative to the total connected load.

In total, residential electric space heating now contributes about 3500 megawatts to winter peak, about 15 per cent of the total system's peak, and it is expected to grow to about 4100 megawatts by the year 2000 in the basic load forecast. Space heating is about 21 per cent of residential electricity use.

We will look next at electric water heating. It is used in 48 per cent of Ontario homes, though its share is forecast to decline over time. It

now accounts for 17 per cent of residential electricity use, a consumption of about 7 terawatthours per year.

There are about 1.3-million electric water heaters in Ontario and each consumes about 5500 kilowatthours per year. Coincident peak demand, and this is also diversified, is .85 kilowatts per water heater. So, the water heating load is about the 1100 megawatts.

Of the remaining 60 per cent of the residential sector load, refrigerators are the largest chunk. They consume 5 terawatthours or 12 per cent of residential electricity use. There are currently 3.6 million refrigerators in Ontario, consuming about 1400 kilowatthours each per year.

New refrigerators in Ontario are estimated to consume about 1200 kilowatthours per year on average. So, the new models are about 200 kilowatthours per year more efficient than the average of the stock as a whole.

Refrigerators have about a 20-year life as I indicated in the example before. So, by the year 2000, half of that 3.6-million stock, 1.8-million refrigerators that exist today are likely to be replaced and an additional 570,000 refrigerators are likely to be purchased for new houses.

The sum of the new and replacement refrigerator stock is 2.4-million units and this is the eligible stock for efficiency improvement in Ontario by the year 2000.

Just to put the total refrigerator load in perspective, the 3.6-million refrigerators we have today in Ontario contribute about 600 megawatts to peak. You could make similar sorts of calculations for most of the other end-uses on this overhead.

Q. All right. Then how was the analysis of EEI potential done in carrying this through for the residential sector?

A. The opportunities for EEI in the residential sector are of two basic types: There are opportunities that relate to the buildings themselves, essentially, the thermal envelope and the heating system; and opportunities that relate to the appliances and other equipment in the buildings, like water heaters and lighting.

No air-conditioning measures were included in this analysis as they do not contribute to reducing winter peak.

The building-related opportunities were analysed separately for existing and new building stock. The results for the existing stock are derived

from the thousand house study.

Now, the final report of this study is filed in something called "The Program Concepts Reference Document". I don't know quite what to say about that, but it is about two feet long and there is a copy in the reference room.

MR. B. CAMPBELL: I think the whole package may be considerably longer than that.

Perhaps, Mr. Chairman, for this purpose, it would simply be easiest in Exhibit 261 to put in as No. 4 the program concept reference document -- or perhaps actually, just rather than that, that will be too much at this point, I think it would just be the final report on the thousand home survey contained in the program concept reference document, which should perhaps be the notation.

THE CHAIRMAN: This would be a new exhibit then?

MR. B. CAMPBELL: It has been supplied in a variety of interrogatories, so I was just going to, rather than list the interrogatory number, simply refer to the document itself that is in the program concept reference document, just under the material that the panel is referring to but not filing.

THE CHAIRMAN: All right. So it should

be recorded somewhere.

Will you put it in with the interrogatory list? Would that be the place to put it?

MR. B. CAMPBELL: Yes, that is what I would suggest, yes.

THE CHAIRMAN: All right.

---EXHIBIT NO. 261.4: Final report of the thousand house study contained in the Program Concept Reference Document.

MR. BURKE: Okay. Well, in that document, the results of that thousand house study are reported. When we did Exhibit 25, only preliminary results were available for 34 out of those thousand houses.

So that the quality of the analysis that we are able to offer in Exhibit 76 is much better than before and it is interesting that the potential is up significantly from 750 megawatts estimated in this component two years ago to 1400 megawatts in Exhibit 76.

Now, the potential in new housing draws on analysis that was available when we did Exhibit 25 and that indicated that there was a potential to save 50 per cent of the electricity use in new housing, but that was relative to the 1986 Ontario Building Code. And since then, the Ontario Building Code has been

revised upward and that has the effect of reducing the savings about 15 per cent on net. I will come back to this point.

MR. B. CAMPBELL: Q. This is another example where the base against which you are measuring changes, has itself changed and, therefore, the savings expressed in percentage terms are just somewhat less?

MR. BURKE: A. That's correct, yes.

THE CHAIRMAN: I am sorry, just is it 35 or?

MR. BURKE: Yes, roughly 35 per cent savings now.

THE CHAIRMAN: 35.

MR. BURKE: The appliance efficiency analysis draws heavily on another consultant study that was submitted in Exhibit 4.7.4. The impact of specific appliance efficiency standards that are already in place or currently anticipated, the ones that we included in the 1990 load forecast, have been netted out when we derived the attainable results.

There is a methodological point that I should mention. It, again, arises because of the timing between doing the 1990 load forecast and completing Exhibit 76; that in Exhibit 76, the estimates of potential and attainable by measure that

are given in that document actually refer to the savings prior to the application of standards and the Ontario Building Code for 1991.

The effect of all of those standards in the Ontario Building Code is netted out in one bottom-line adjustment in Section 5 of that document, but it wasn't possible to do both sequentially so they were done in parallel and the adjustments made at the end of the report.

MR. B. CAMPBELL: Q. All right. Now, how did the thousand house study estimate EEI potential for existing electrically-heated houses in Ontario?

MR. BURKE: A. Well, the thousand house study may be one of the best data bases on electrically-heated houses anywhere. The thousand houses were carefully selected to be a statistically representative sample of the electrically-heated housing stock in Ontario.

For each house in the sample, there was a telephone questionnaire followed up by a three to four hour on-site audit of the house. And for about 100 of these houses, fan tests were done to determine air infiltration rates, which is a key element in heat loss and one which is rarely actually measured.

A long list of candidate upgrades were

screened for feasibility to determine a recommended upgrade package for each individual house. These recommendations were made by expert home auditors.

The result is a wealth of data and that data makes it clear that there is quite a diverse housing stock in Ontario that it is very difficult to, in fact, come up with a few typical houses that adequately represent the housing stock that we have.

There are different types of houses. The different houses themselves are in different states of upgrade in terms of their thermal envelope.

And so, rather than try to develop a few typical houses to work with just like we had typical buildings in the commercial sector, we have exploited the property that the sample is representative of the province as a whole and we have extrapolated the results of the thousand house study to the population as a whole.

So, each house was analysed individually to assess the optimum economic package of measures that could be put into that house and these do vary widely.

We tried to make sure that the savings that we were estimating for each house were realistic by taking some pain to tie the heating load, the reduced heating load, to the estimated bills of these

customers to extract from the building data, a reasonable estimate of what their normal heating load would be and then using models determine what the expected savings of this package of retrofit measures would yield.

In the tables that are given in Exhibit 76, the costs in energy savings of each technology represent the extrapolation to the entire stock of Ontario electrically-heated houses of the incidence of each application of a particular technology in the thousand house sample. Perhaps you could put this overhead on.

Page 31 of Exhibit 260 gives you a series of the major measures that were applied to each of these houses and not all of the measures were applied in each house; some of them more than others in particular houses. Each instance is unique and each was analyzed. And then the basis of the total province-wide assessment being an inference from the sample to the population as a whole.

When we looked at the thermal envelope -- well, I should say, we looked at the thermal envelope first and then after we had done the various upgrade measures that were economic, it was then -- the question was asked, what was the best heat pump that

you could put into the house to supply the remainder of the space heating requirements?

As air source heat pumps save very little load at the time of winter peak, they were rarely selected. Ground source heat pumps save on average about 5.3 kilowatthours out of that seven I mentioned earlier on the coldest day of the winter and burners --

Q. 5.3 kilowatts?

A. Kilowatts, yes, per house.

Q. Not kilowatthours?

A. No, kilowatts, connected peak at the time of -- on the coldest day of the winter. And burner-assisted heat pumps save about 3.1 kilowatts. So, these thermal envelope measures were complemented by the appropriate heat pump choice.

The complete analysis is documented in the thousand house study final report I mentioned and it is summarized in Exhibit 76. Exhibit 76 does update the numbers slightly for the fact that it is about two years since some of those numbers were generated for the thousand house study and there is a larger stock to work with.

So, the numbers in Exhibit 76 differ slightly from the numbers reported in the thousand house study.

The savings total 1400 megawatts and that is about 41 per cent of the electric space heating use in Ontario.

Q. All right. And that applies to the existing stock.

What was the savings rate in new housing stock?

A. Well, as Mr. Saunders quickly calculated, we are now using a savings rate of 35 per cent relative to the 1991 Ontario Building Code. And I would point out that the R2000 house was still used as a benchmark for cost-effective new house savings because its costs and savings are pretty well understood.

The life cycle premium cost or incremental cost of an R2000 house is nearly 5 cents a kilowatthour. The avoided cost for this kind of load is about 6.6 cents a kilowatthour. So, there is some room there for further cost-effective insulation or other measures to increase the efficiency of those houses, but we really have little experience with which to work and so we have kept with the R2000 concept for the purpose of estimating EEI potential in new housing.

...

[2:48 p.m.] Q. What are the total savings in building-related load in the residential sector?

A. That's the bottom line on page 31 of Exhibit 260. By the year 2000, a building related load has a potential induced EEI of about 1750 megawatts. If you take the 19 -- now that is a number that comes from Exhibit 76.

So, I'm going to do something that I will have to do a few times in the remainder of this talk, which is to say what that number would be if you took out the standards and so on that are in the 1990 load forecast, item by item rather than in a bottom line way, as we did in Exhibit 76.

If you take out that amount, you'd be reducing this by about 100 megawatts to 1,650 megawatts, or about 40 per cent of year 2000 residential space heating load.

Q. The reference there is to the effect of the 1991 Ontario Building Code changes?

A. Yes, that 15 per cent extra that we can count on through the 1991 Ontario Building Code relative to the 1986 Ontario Building Code knocks off about 100 megawatts. Because that is already captured in the basic load forecast.

Q. Now, I'd then like to turn to the

non-building related savings, and perhaps you could go through the major savings opportunities in the residential sector in that area.

A. Overhead 32 in Exhibit 260 gives a list of the non-building related opportunities. Total saving potential estimated for appliances including lighting and water heating is about 600 megawatts in the year 2000 or by the year 2000. Of these, about 270 megawatts relates to lower water heating energy use, electric energy use. And these savings are scattered through some of the entries in this table. There is about 80 megawatts of savings due to reduced requirements for hot water by clothes washers and dishwashers. Effectively the efficiency gains for those two appliances are the reduced hot water requirements.

There is also about 70 megawatts associated with efficiency improvements in the water heaters themselves. And those items on the overhead are tank wrap and heat wrap measures, and they add, as I said, about 70 megawatts of savings.

And finally, reducing the amount of hot water required for showers through low flow shower heads contributes 120 megawatts or so, as indicated in that overhead.

So, having taken those items off the list, the largest remaining one is the refrigerator at the top at 132 megawatts. And that is 132 megawatts before the new standard comes into effect in Ontario in 1994. If you take the effect of the higher standard into account, the potential for refrigerators is 87 megawatts on net, in Hydro's analysis.

Q. All right, could you explain how the refrigerator potential induced EEI is derived in the case where, as I understand is proposed, the 1993 U.S. standard is to be applied in 1994 in Ontario?

A. Yes, this overhead, No. 33 in Exhibit 260, illustrates the change in electricity use between the basic load forecast -- sorry, in the basic load forecast over time, and in the forecast of electrical efficiency improvement for refrigerators.

In the basic load forecast, this is a number I mentioned earlier, it was estimated that new refrigerators would consume about 1,200 kilowatthours per year on average in 1990, and again, in the basic loads forecast prior to 1994, it is assumed that refrigerators would be about 10 per cent more efficient than the 1990 base. But then all of a sudden, as you see in 1994, between 1994 and 2000, with the standard, the efficiency gain shoots up. The number that is

shown is about a 30 per cent improvement relative to the 1990 base and yields an annual consumption of about 800 kilowatthours per year.

The pure effect of the standard is 45 per cent saving, which would be a more significant efficiency improvement than we have indicated here. But it was anticipated that increases in size and the features of the refrigerators, plus some moderation in the impact of the standard due to delayed purchasing of secondary -- the delayed impact of the standards on secondary units, would reduce the average saving per refrigerator to about 30 per cent value that is in the basic load forecast. So, while 45 per cent is the pure efficiency gain, 30 per cent is the reduction in use of the average refrigerator for those years.

Now, on the EEI line the reduction in electricity consumption by the year 2000 is about 60 per cent. It averages about 48 per cent over the decade, starting off somewhat lower, around 20 per cent at the beginning of the decade, and rising to about 50 per cent in 1994. And then moving up again another notch in '97 to 60 per cent.

The fact that we have got the potential for refrigerator efficiency improvement rising like this reflects the practicality of actually acquiring

efficient refrigerators for use in Ontario. We simply could not find anywhere in the world 250,000 refrigerators for Ontario's use that were 60 per cent more efficient than the ones we are consuming today -- than the refrigerators that we have today in Ontario. It is not -- they don't exist. So, we have phased in the efficiency gains. And that is what is reflected in this ramp up in the potential line.

By the year 2000, 60 per cent efficiency improvement corresponds to annual consumption of 500 kilowatthours per year for new refrigerators. And this level is probably lower than the amount that one might reasonably anticipate to result from a 1998 U.S. standard.

As you may recall, in Panel 1 we discussed the fact that the U.S. standards are likely to be revised in the future. It is very difficult to anticipate exactly where they are going to go, but in the case of refrigerators, Lawrence Berkeley labs has supplied analysis to the Department of Energy in support of the Act, the U.S. National Appliance Energy Efficiency Conservation Act, which suggests that the cost effective next step for standards would probably be a refrigerator that consumes more than 500 kilowatthours per year, even in 1998.

I guess what I'm trying to point out is the standards, the level that we have in our EEI potential estimate is a healthy one and is likely to result in refrigerators that exceed the U.S., the next set of U.S. standards.

You'd have to say, though, that in the case of refrigerators, we have pushed our analysis a little bit beyond what has been commercially demonstrated to be economic, and this is probably the only technology we do this for, and I think quite a few other studies have done this as well, and it probably results from the fact that Lawrence Berkeley Labs has done so much research into refrigerators that people actually believe their laboratory numbers.

I think it is worth pointing out that in 1988 there were no commercially available U.S. refrigerators that could meet the 1993 standard that was set under that U.S. Appliance Efficiency Act, but there are now several models available in the U.S. that can meet the 1997 efficiency level that we have in our EEI potential forecast. The only problem with them is that they are not economic yet.

Q. All right. Now, I want to turn your attention away from refrigerators, everyone will be thankful to hear, and you probably as much as everybody

else, but I'd like you to turn then to compact fluorescents, which is something that Hydro has certainly promoted. And as I understand it, compact fluorescents save about 75 per cent of the electricity consumed by a 60 watt incandescent bulb, and I'd ask you what the potential is for savings in Ontario by the year 2000 from that source?

A. Our estimate of the potential for savings due to compact fluorescent bulbs in Ontario by the year 2000 is 72 megawatts. Now, this might seem like a small number, but actually one of the examples that Mr. Shalaby showed this morning was the total customer cost test of the compact fluorescent bulb. And its economics, as you may recall, while it passed the test, it just barely passed the test. That was based on the fact -- it resulted from the fact that in typical applications, these bulbs are only used a few hours a day.

Now, the economics of that total customer cost test that you looked at did not take into account any costs associated with changing the fixture that the bulb actually goes into. Now, if you had included the cost of a new fixture, compact fluorescents wouldn't be economic at all.

Hydro estimates that about 15 per cent of

the 26 bulbs that are used in an average Ontario house would be appropriate for replacement by a compact fluorescent lamp. What this does is effectively reduce the per house savings to about 11 per cent from the 75 per cent that one might infer if all of the bulbs in the house were replaced by compact fluorescents.

But there are a lot of houses, 3.1 million houses, at 120 kilowatthours per house per year, and the annual energy savings amount to about 330 gigawatt hours, or the 72 megawatt number that I suggested. This is about .7 per cent of year 2000 residential energy demand.

Q. What is your total for the residential sector?

A. Page 34 of Exhibit 260 adds up the savings for each of the major elements I have been discussing. For the residential sector it is 2,400 megawatts. That takes you up to the last line in the table, which is the agricultural segment, and that's one of the reasons our number has changed this year. We did not estimate the agriculture segment's potential in 1988, and it is now estimated to be 136 megawatts by the year 2000.

So, the residential agricultural total is 2,500 megawatts, as shown in the overhead, and that's

consistent with Exhibit 76. If you take into account the standards that were introduced in the 1990 load forecast, it is closer to 2,300 megawatts remaining.

Q. All right, now again, what is the cost of these residential measures?

A. My third and final load reduction curve for the residential sector shows that the measures are spread out much more along the cost axis. Only 20 per cent of the savings in the sector can be obtained for less than about three-and-a-half cents a kilowatthour, and about 30 per cent, basically the last step, indicated by the word "heat pump" at about six-and-a-half cents a kilowatthour, is quite expensive, but it is cost effective, because the avoided cost in space heating applications about 6.6 cents per kilowatthour. So, the residential sector has high cost measures, but benefits from the fact that the avoided cost in many of its end-uses is also very high.

Q. Now, I'm going to ask you to pull together some of the elements of the discussion of the different sectors and outline the results of your analysis of the total potential induced EEI for the three sectors.

A. Page 36 of Exhibit 260 gives a total, summing up the numbers that I have described for the

year 2000. It comes to 6,400 megawatts in the year 2000, as per Exhibit 76. By the year 2015, the total potential is higher, it is 8,900 megawatts. The impact of standards that are included in the 1990 load forecast is about 200 megawatts in the year 2000. We estimated 215. So that makes the potential induced EI after the standards, which is really the correct way of doing it, 6,200 megawatts, and by the year 2015, the total is 8,600 megawatts.

...

[3:03 p.m.] Q. How were the results for 2015 derived?

A. Well, the results for 2015 apply the same rate of savings that we have analyzed in great detail for the year 2000 to the forecasted load growth by segment right through to 2015.

One thing that one can observe is that in the subsequent 15 years the potential doesn't grow nearly as much as the total potential in the first 10, and the reason for that is that a large part of the existing capital stock has already been included in the year 2000 potential estimate.

Only existing equipment with life greater than 10 years has remaining potential, that is amongst the existing stock, beyond the year 2000. There may be a few renovation possibilities left after the year 2000, but the retrofit measures in existing houses and in existing commercial buildings to the envelopes are all assumed to be complete by the year 2000.

So, the only remaining source of new EEI potential is new equipment and new buildings, and this offers much less incremental scope for megawatt savings than the once over retrofit of the existing stock.

Q. And what proportion of total system peak in the year 2000 does potential EEI represent?

A. Well, the 6200 megawatts of potential induced EEI corresponds to about 19 per cent of the peak load we projected in the 1990 basic load forecast. Because some studies report these results relative to the starting year load, it would be 26 per cent reduction relative to 1990 load. Again, we will look at the relevance of that sort of number later on in the discussion.

Q. Now, how does the potential induced EEI in Exhibit 76 compare to the total presented in the DSP in Exhibit 25?

A. Page 37 of Exhibit 260 provides you with the estimates that were included in Exhibit 25 under the DSP column, and Exhibit 76 under the 1990 load forecast column. And you can see that the change of 1450 megawatts is spread fairly even across the sectors.

The explanation for the change is given in the next overhead, overhead 38 of Exhibit 260. In the residential sector a major factor was the incorporation of the results of the thousand house study. Also we included the agricultural segment. And finally, there were some new technologies added, including compact fluorescents whose impact had not been estimated previously.

In the commercial sector we have mentioned the technologies we have added, the electronic ballast, and ground source heat pump and window film for space heating purposes.

And finally, there was an explicit recognition in the industrial sector of 380 megawatts of potential savings that we haven't yet specified, and so that contributes to the higher total.

THE CHAIRMAN: How are you able to come to that figure if you haven't specified it?

MR. BURKE: Well, I think the short answer is it represents the best judgment of the industrial sector analysts that worked on this, but they, as we admit in Exhibit 76, really don't have a lot of good information to work with at this stage as far as process specific changes are concerned, and it may be conservative. But this number is considered to be a reasonable estimate. You are right, we do need further analysis to --

THE CHAIRMAN: Compared to 520, 380 of hard, if I can put it that way, analysis, 380 is a pretty large figure.

MR. BURKE: Yes, but there are a variety of U.S. studies that indicate that there is an increased potential in specific industry applications

and the difficulty is knowing how the American experience would apply in Canada and the extent to which we can generalize from specific industry studies to the industrial sector as a whole. All I can say is that the 380 megawatts is our best estimate at this time and we intend to look at it further.

THE CHAIRMAN: Is that approach consistent with your statement a few minutes ago that things are going to go down at the end of 10 years because we have really run out of programs and techniques and we can only use new houses and new stock?

MR. BURKE: Well, I wasn't saying potential was going to go down; it's only going to grow more slowly.

I am not sure that there is actually a relationship between how we have estimated potential in the industrial sector and that trend. Effectively in the industrial sector, the trending beyond the year 2000 is pretty well the function of the load of the industrial sector. It's not distinguishing between new and existing in the same way that we have for residential and commercial.

THE CHAIRMAN: Thank you.

MR. B. CAMBPELL: Q. All right, Mr.

Burke, I want to turn you then, please, to the role of standards, and you have indicated that the 1990 basic load forecast includes a set of standards which will reduce load by 215 megawatts in the year 2000. I would like you to explain how the impact on the primary load forecast was then calculated.

MR. BURKE: A. The standards taken into account in the 1990 basic load forecast overlap some of the areas that we had included in induced EEI potential. So, effectively, the potential EEI was reduced by the full 250 megawatts associated with the incremental impact of the standards.

But when we turn now to attainable EEI, the reduction in attainable EEI depends on the penetration rate of the demand management programs that we have built into the analysis where those standards apply. And the estimate that was made, and it is actually presented in the 1990 load forecast document, I guess Exhibit 9, is that 53 megawatts of the EEI programs would be displaced by the standards, the estimate is also in Exhibit 76.

So, as a result, the 215 megawatts of impact on potential is reduced to 162 megawatt impact on the basic load -- on the primary load, rather.

Q. If standards were applied more

broadly or set at higher levels, how would that affect primary load?

A. The sort of calculation one would do would be analagous to the one we have done already. If you broaden the application of standards, you would increase the amount by which potential induced would fall, and the primary load would be reduced by the net of that change in potential and the proportion that you have already accounted for or expect to capture with programs. So, effectively, the standard gets 100 per cent penetration of the market, our programs might have assumed 30 per cent of the market, you are getting an extra 70 per cent market penetration because you have adopted a standard rather than relied on a program.

Q. And that obviously lowers the level of the primary load in the final analysis?

A. Yes.

Q. All right. Now, could standards be applied to all of the segments that Hydro has included in its analysis of potential induced EEI?

A. Well, the short answer is no. Setting standards is not a simple task and it is rendered more difficult the less homogeneous the segment that you are trying to regulate is.

We have examined our list of efficient

technologies - that is included in the appendix to Exhibit 76 - and we have identified the ones that we think could be subject to standards in Ontario.

This list here is a selection, sort of a summary version of the technologies that are given in exhibit -- sorry. These technologies here, on page 39 of Exhibit 260, are from Exhibit 258, and there we have a listing of just those technologies that we were using to calculate potential induced EEI that would be eligible for standards. And in the residential sector, in existing buildings, only doors and windows are sufficiently standardizable, that you could really expect to write a standard for them.

The R2000 house could become a new building code, and of course appliances and water heating and lighting, all of those are opportunities for standard setting.

When you look at the total for the sector, about 45 per cent of the potential that we have identified for residential efficiency improvement is eligible for standards. And again, the major part that's missing is most of existing -- most of the load in existing electrically heated houses is not really amenable to standard setting.

In the commercial sector, the lighting

fixtures themselves could be standardized, although probably things like how you redesign lighting systems and how you control them would be difficult to standardize.

Motors, windows, water heating, the appliances that are used in the multi-residential portion of the sector and heat recovery ventilators are all eligible for standards. And again, the total for the commercial sector is about 50 per cent of commercial sector identified potential eligible for standards.

The industrial sector continues to be the most heterogeneous of the lot. And from our perspective, only motors, lighting and some refrigeration applications could be standardized, and of the number we estimated for potential only 14 per cent eligible for standards.

So, that in total --

THE CHAIRMAN: You must have given a percentage of commercial. What was it?

MR. BURKE: About 50 per cent.

THE CHAIRMAN: 50?

MR. BURKE: Yes.

And page 40 of Exhibit 260 gives the totals, starting with the 6200 megawatts of potential

induced that we estimated net of the standards assumed in the basic. And then looking at the loads eligible for standards, were the standards to be in effect between 1991 and the year 2000, and that is about 2600 megawatts, it is less than half of the total potential induced and for the reasons I have given, that there are large elements of the industrial sector and the residential sector and the less homogeneous features of the commercial sector that we don't see an easy way to set standards for.

MR. B. CAMBPELL: Q. Now, I guess the first question in this area of standards that sort of comes to mind because they seem sometimes so straightforward is simply this: Could standards be implemented in Ontario sort of next year, right next year, or right this year to achieve maximum economic potential? Do you think that's a reasonable proposition?

MR. BURKE: A. I don't think it's feasible for two reasons, the first is timing and the second concerns this issue of trying to set standards at the maximum economic efficiency level at all. Let's start with the timing.

Even without a consultative process, and this does seem to be the process that the current

government favours, standards would take time to write, I would think about a year for a typical standard.

And if the standard really was aggressive, I think it could only be meaningfully implemented by appliance-makers if you gave them two or three years' notice. There just wouldn't be the product in the marketplace without some notice.

So, when we looked at the scenarios in Exhibit 258 and looked at bringing in more aggressive standards, we assumed that 1995 would be the first year that higher standards or standards in new areas could come into effect, and that is in addition to the standards we have already considered in the load forecast which range in years up to 1994.

Q. All right. Now, what about your second concern, are standards normally set at the maximum economic efficiency level?

A. No, they are not. Appliance efficiency standards are usually designed to eliminate the most inefficient products from the marketplace. The U.S. National Appliance Energy Efficiency Act goes perhaps a little bit beyond that. It's intended to lead the marketplace.

...

[3:19 p.m.] But efficiency improvements must still have a three year payback from the perspective of manufacturer's cost and this is an easier criterion to meet than meeting a total customer cost test.

So I would say that setting a standard to achieve maximum economic efficiency gain as estimated by the total customer cost test would be unusual. I don't think anybody has set a standard that way up to now in North America.

Q. And what kind of scenarios for more aggressive EEI standards has Hydro considered?

A. Well, as we discussed in Panel 1, it is very difficult to try to anticipate exactly how U.S. appliance efficiency regulations are going to evolve or even how the Ontario Building Code will evolve. So, we have taken a simple route and derived two cases that relate to our estimate of potential induced EEI. The first assumes that you could regulate achievement of 100 per cent of the maximum economic efficiency gain in the eligible end-uses as screened for Hydro's estimates of potential induced EEI starting in 1995. That is one case.

The second case is simply getting half of that by setting the standard at 50 per cent of the difference between the natural efficiency gain level

and the maximum economic efficiency gain level, but again, starting in 1995 and going to the year 2000.

Well, it would go beyond 2,000 but our analysis stopped in the year 2000.

Q. What would the load reduction due to standards, these kinds of standards be, by the year 2000 in each case?

A. Okay. Well, in the maximum case, that first case I mentioned, we would be looking at savings for the period 1995 to 2,000, and that is the third line on page 40 of Exhibit 260. And essentially what we are getting there is about 60 per cent of the potential that was identified for the period 1991 to 2000 and that is simply because the standards would be in effect six out of the ten years.

It is not exactly that because some of the technologies do have a wrap-up in potential, as I discussed earlier, but that is broadly speaking what it would be. The 50 per cent case simply yields half of that, about 800 megawatts by the year 2000.

Q. How would the total net load impact of EEI be altered in these cases?

A. The electrical efficiency improvement programs in areas where standards are applicable, or expected to achieve a penetration rate of about 30 per

cent on average in the study done for Exhibit 76. So that means that standards would increase, year 2000 attainable EEI, by 70 per cent of the amounts that I have just given you, and that works out to -- 70 per cent of 1600 works out to about 1100 megawatts in the case of 100 per cent standards and 550 megawatts in the case of the 50 per cent standards.

Q. And are the estimates of savings due to efficiency standards independent of the potential for fuel switching?

A. No. We haven't got to the end of this yet. In some end-uses, such as residential space and water heating, efficiency improvement standards would be redundant where fuel switching is feasible.

So, once I discuss the fuel switching, I will come back to address the overlap between fuel switching and the potential induced EEI and the savings you could get through standards. The results you get when you take all of that into account are contained in Exhibit 258 for cases A to E.

I should say that in order to do the analysis in Exhibit 258, we had to be able to consistently calculate between fuel switching and our EEI potential, and so we made the same assumptions as we used in Exhibit 76 as far as the data set that we

were working with.

That means, as I mentioned at the beginning, that it was the 1990 load forecast that was used for the residential sector and the '89 load forecast for the commercial and industrial sectors.

MR. B. CAMPBELL: All right. Now, Mr. Chairman, I am about to turn to a discussion of the fuel switching potential and although it is a few minutes earlier than we normally take the break, I think it is a good time.

THE CHAIRMAN: All right. We have to stop at a quarter to five tonight. I just want to let people know that. Okay, a 15-minute break.

---Recess at 3:23 p.m.

---On resuming at 3:44 p.m.

THE CHAIRMAN: Please be seated.

MR. B. CAMPBELL: Mr. Chairman.

THE CHAIRMAN: Okay.

MR. B. CAMPBELL: Q. All right, Mr. Burke, I think just as a logical point to turn your attention to fuel switching and how it could impact on both EEI potential and total demand management potential.

And again, I would first by asking you to identify what analysis Hydro has done to date

concerning fuel switching opportunities.

MR. BURKE: A. Recently, Hydro prepared some preliminary estimates of fuel switching potential and the reduction in electrical efficiency improvement potential that would go along with it. These estimates are contained in the report filed as Exhibit 257, fuel switching potential in Ontario by the year 2000.

Q. And now before you explain how the numbers are derived, could you give the Board, please, a sense of the bottom line of this analysis?

A. Overhead 41 of Exhibit 260 gives the results of the analysis, the pure fuel switching potential by the year 2000. The amount of electricity that could be switched economically - and by economically, I mean in the sense of, would pass the total customer cost test - from electricity to natural gas is estimated to be 3100 megawatts by the year 2000, considering both existing and new electric load and end-uses which are eligible to be switched to gas.

Now, where oil and propane in non-gas available areas to be viewed as appropriate off electricity fuels - and really, we are looking still for guidance from the government here as to whether that is appropriate - then there would be another 1600 megawatts of potential, which brings the total and the

bottom line here of 4700 megawatts. But Hydro has focused its analysis on the potential to convert to gas alone.

Now, that 3100 megawatts of fuel switching to gas can't simply be added to the 6200 megawatts of potential EEI as we have been saying. In fact, the overlap is about a thousand megawatts as indicated on page 42 of Exhibit 260. This is the amount of electrical efficiency improvement that was economic and so included in our EEI potential estimate that would no longer be relevant given that the loads were converted to gas.

Q. All right. And what are the eligible markets for fuel switching from electricity to natural gas in Ontario?

A. Well, in principle, there are opportunities in each of the three end-use sectors, essentially, wherever electricity is used to provide heat using electric resistance heating technology.

In the industrial sector, the potential is extremely limited. Less than 1 per cent of total sector load is used for space heating, so we haven't pursued that end use further.

Where electric resistance heat is used in industrial processes, we have assumed that other

production considerations would limit the ability of that industry to switch to gas. So, the major opportunies we are looking at are in the residential and commercial sectors.

I should also point out that because Ontario Hydro is a winter peaking utility, the use of gas chillers as a substitute for air-conditioning in the commercial and perhaps in the residential sectors was not pursued. Now, gas chillers have been found to be cost effective on a lifecycle basis in some U.S. summer peaking utilities, but given that we are winter peaking, we do not find them to be so.

Q. All right. Now, what is the eligible market in the residential sector?

A. Well, the candidates are space heating, water heating, cooking and clothes dryers. Essentially, we have eliminated cooking and clothes dryers because we think consumers might object to being obliged to switch in those end uses. And so, in fact, we are focusing on space heating and water heating for the purpose of this study.

Q. All right. And I would like you to look at the eligible market then for switching those space heating fuels.

A. Well, electric space heating, as

might be expected, is the major opportunity in the residential sector. I am going to take you through this - well, I don't know whether it looks like a complicated overhead - page 43 of Exhibit 260, but I am going to try to pare down for you what the eligible market is in the floor space heating in the residential sector.

You may recall when I said that we are assuming 500,000 electrically-heated houses in Ontario in 1990. One third of these has central heating systems, either central furnaces or all-electric heat pumps. The remaining two thirds have baseboard heating.

Q. Now, why do you distinguish between central heating systems and baseboard heating?

A. Well, central heating systems have duct work built into the house and so can accommodate a gas furnace without having to install new ducts. In that circumstance, the economics of conversion to gas are quite favourable in Hydro's analysis.

Baseboard-heated houses do not have duct work and face between 2-1/2 thousand and $6,000 extra cost to convert to gas.

Now, when we applied the total customer cost test to baseboard-heated houses, expenditures of

up to $4,000 on duct work retrofits were cost justified. In fact, Mr. Shalaby gave you the bare bones of that analysis earlier, although it might have been difficult to see where that $4,000 number comes from. The details are given though in Exhibit 257.

This limited cost-effective fuel switching to single-storey dwellings -- that is, it is cheaper to install ducts in single-storey dwellings than in two-storey dwellings -- and so the eligible potential, economically, is about half the baseboard-heated houses in Ontario.

So, looking at this pie chart here on page 43 of Exhibit 260, we started with 500,000 houses. A third of them are centrally heated with -- and so are eligible, and half of the baseboard-heated houses are eligible, another 167,000.

So, the total eligible stock, were the availability of fuel not an issue, is 335,000 houses altogether.

Q. All right. And where then does natural gas availability fit into this analysis?

A. Hydro's 1990 residential appliance survey indicated that roughly half of the houses that are electrically-heated have gas available.

Now, you may recall in Panel 1 we had

some discussion about the gas availability in Ontario and the number 75 per cent was the number that was quoted at that time. I want to point out that that referred to something slightly different. That number refers to the proportion of all houses in Ontario for which gas is available.

Electrically-heated houses are disproportionately rural and have a much lower market share in areas where gas is available. So, that is why a proportion of electrically-heated houses that have the option to go to gas is about 50 per cent.

Because gas is only an option for half of the electrically-heated houses that are eligible which were, in turn, two thirds of the original 500,000, the eligible houses for conversion to gas are 167,000, as indicated in that overhead.

Q. And what is the situation for new houses?

A. Again, because of gas availability, half of all new electrically-heated houses that are forecast to be built between now and the year 2000 - that is half of the 140 --

THE CHAIRMAN: I am sorry, I have lost your mathematics.

You say half of the existing

electrically-heated houses are eligible; is that what you said?

MR. BURKE: I said half of the eligible portion and the eligible portion --

THE CHAIRMAN: Let's go back to the eligible portion.

MR. BURKE: Yes.

THE CHAIRMAN: I am looking at Exhibit 43 on the left-hand -- what is eligible and what isn't eligible in that?

MR. BURKE: Centreal heating -- houses that are heated centrally and have the duct work in place are all eligible.

THE CHAIRMAN: Wait a minute. How do I find that from that diagram?

MR. BURKE: Well, of the 500,000 electrically-heated houses - we are accounting for them all here - and --

THE CHAIRMAN: See, it looks like to me - perhaps I am wrong - it looks to me as if you have put a line running through the middle of central heating.

MR. BURKE: That's correct.

THE CHAIRMAN: Which shows half of them available.

MR. BURKE: Half of them are in areas

where gas is available, and so there are 167,000 centrally heated by electricity houses in Ontario and of those, we estimate half are in areas where gas is available to them.

...

[3:54 p.m.] THE CHAIRMAN: All right.

MR. BURKE: And similarly, there are 335,000 baseboard-heated houses in total, but we said that it would only be economic to convert to gas, and in the process install duct work, for the one-story baseboard-heated houses.

THE CHAIRMAN: You didn't say that, but that is the reason. Is that why the arrow goes, is that right?

MR. BURKE: That's right. So, we split the baseboard-heated houses in two, and it does turn out from our survey data that half of the baseboard-heated houses are one-storey, and half are one-storey or more.

THE CHAIRMAN: So, the approximate breakdown is very neatly a third each way, is that right?

MR. BURKE: It is too neat, I agree, but that is the way the survey results come out. There are about four numbers, 167,000 on the page here, but essentially we are taking a half of two-thirds of the market.

THE CHAIRMAN: All right, I understand.

MR. B. CAMPBELL: Q. Okay, new houses.

MR. BURKE: A. New houses, right. We

are going to take half of the eligible new houses, and we are forecasting 140,000 new electrically heated houses between 1991 and 2000. So that is an additional 70,000 houses would have been heated electrically in gas available areas. We will just say, "Don't heat electrically." So the total, that number of houses that could be switched is 237, according to the information on page 43.

The next overhead, page 44, shows that the amount of savings per unit that we are attributing to this fuel switching, to make life simple, and I don't think there is a huge amount of loss in this approximation, we have used the year 2000 electricity savings per unit as the amount that we'd save per household. And that yields for the existing houses 960 megawatts of peak production, and for the new houses about 375 megawatts of peak production, for a total of 1,336 megawatts, as estimated in Exhibit 257.

Q. Then with that background on space heating, I then want you to address the opportunity for converting electric water heaters to gas.

A. Well, in 1990 -- I'm going to take the same approach. In 1990 there were 1,260,000 electric water heaters in Ontario. Of these, 250,000 are in gas heated houses. So because the pipeline from

the street to the house essentially is already there, all of these could convert to gas economically.

I have just finished showing that there are 167,000 electric space-heated houses that could be converted to gas for space heating purposes, and in so doing, it would also be economic to convert the water heaters in those houses. So, there is an additional 167,000 electrically heated houses that are eligible to convert to gas. And that's the portion separated out on the bottom right-hand portion of the pie chart, roughly between three and five o'clock there in the pie chart.

The remaining water heaters really have marginal economics for conversion to gas, because they would not be in houses that were heated by gas. For instance, there are 430,000 houses still heated by oil in Ontario that have electric water heaters, and it would not be economic to convert these to gas, to convert the water heaters to gas. We are not yet getting into the business of converting the oil people to something else. Just we're talking about whether it would be economic to convert electrically heated water heaters in oil heated houses to gas, and we are saying that is not on. So, the total potential that we have estimated is based on 420,000 eligible water heaters.

In the new stock, we are forecasting 190,000 electrically heated water heaters to be added in the next ten years, and again, half of these are eligible where gas is available. So, that adds about 95,000 units and brings the total to 515,000 water heaters that could be switched.

And similarly the savings per kilowatthour are given on page 46 of Exhibit 260. I may not have mentioned that.

THE CHAIRMAN: I hate do this again to you, but what did you say the total was, four --

MR. BURKE: 420,000.

THE CHAIRMAN: That's made up of 250 plus 167, is that right?

MR. BURKE: That's correct, yes.

MR. B. CAMPBELL: Q. And that is for existing?

MR. BURKE: A. That is for existing alone.

Q. And in addition, for new?

A. 95,000.

Q. For a total of?

A. 515,000 water heaters.

Q. All right. Now --

A. On page -- I may, just to be

indicating, that those pie charts were on page 45 of Exhibit 260. I may have not slipped that in before.

Now, I'm moving to page 46 of Exhibit 260, and this gives the kilowatthour savings per water heater in the various applications, and the total megawatt saving, which is 430 megawatts.

Q. All right, so what then, if you take all of this together, space heating and water heating, what is the total fuel switching potential, according to these calculations, for the residential sector?

A. Well, as shown on page 47 of Exhibit 260, the answer is 1,765 megawatts.

Q. Now what commercial sector loads were considered eligible for fuel switching to gas?

A. First of all, I should point out that we have assumed that all commercial buildings are in areas served by natural gas. This may be a little generous. We are checking to see how far off that is, but I don't think it is off by much.

Also, I think I'd have to observe that we have much better information about the electrically heated housing stock than we have about the electrically heated commercial building stock. So the numbers for new and existing commercial heating probably require more empirical investigation than the

ones we have used for the residential sector. They are a little bit more speculative.

Nonetheless, in commercial buildings where baseboards are used, duct work is very costly to retrofit, and we've assumed prohibitively so. So Hydro has assumed that 25 per cent of existing commercial space heating load is eligible to convert to gas.

For new buildings, it is assumed that it is technically possible and economic for all electric space heat to be replaced by gas. This again may be generous, in the sense that we have assigned all of the load associated with electric space heating in new buildings to this switching, because included in that would be some applications of heat pumps, which improve the overall energy efficiency of the building and probably should be continued in any efficient building design. So again, we may have overstated the commercial because of that.

Q. All right, given all of that, what is the estimated fuel switching potential?

A. Page 49 of Exhibit 260 shows the various categories; the 25 per cent eligible for existing buildings yielding 1,473 gigawatt hour savings, and a load reduction of 560 megawatts.

For anybody who is doing the fine points

on this calculation, I remind you again this is the 1989 load forecast commercial space heating estimate that yields these numbers.

New buildings, 100 per cent eligibility, savings of 795 megawatts, for a total of 1,360 megawatts or so for the commercial sector shows switching potential by the year 2000.

Q. So that figure is the total fuel switching potential?

A. No, that was the total for commercial. You'd have to add, in the next overhead we show on page 50, you'd have to add the 1,765 for the residential sector to get the total fuel switching potential.

Q. That gives us, judging by that, about 3,100 megawatts?

A. That's correct.

Q. That can be found on page 50?

A. Page 50 of Exhibit 260.

Q. Now in this space and water heating end uses, there is obviously a fair bit of potential as well for energy efficiency improvements. I want you to address the question of what reduction result to the potential for energy efficient -- for electricity efficiency improvements, given that these systems have

been switched to gas.

A. Yes, this is summarized on page 41 of Exhibit 260.

Q. 51?

A. 51 of Exhibit 260, and it shows that because of fuel switching, the efficiency improvement potential for residential space heating would not be applicable in one-third of existing houses and a half of new houses, and similar proportions apply for water heating.

When you look at the electrical efficiency improvement measures for space and water heating in the residential sector, these represent 2,000 megawatts out of the 2,500 megawatts of potential that were estimated in Exhibit 76. So applying these proportions I mentioned yield 710 megawatts of EEI potential that would no longer be available.

Now thermal envelope upgrading and heating system improvements were less significant in the commercial sector. The estimate of the foregone EEI potential is 300 megawatts or so in the commercial sector. And so the total offset to the fuel switching is 1,000 megawatt reduction, the inefficiency improvement potential, and that takes the EEI numbers before fuel switching down from 6,200 to 5,200,

correcting for the standards question. The numbers on page 51 are all consistent with Exhibit 76 and Exhibit 257. But as I say, there is this extra 200 to net out.

Q. All right, now when you were reporting on economic conversions to gas, what assumptions did the total customer cost test make about the future avoided cost of gas in the residential sector?

A. Mr. Shalaby alluded to this issue this morning, when he talked about the application of the total customer cost test to fuel switching, as opposed to simply efficiency improvement.

Hydro has not done its own analysis of the avoided cost of gas in Ontario, either in the short run or the long run. And as a proxy, we have used the price forecast for gas contained in the 1990 Energy Price Trends Report, which is Exhibit 14, and actually that forecast is on page 42.

So we did the cost effectiveness analysis using that price forecast as a proxy, and we did it in two time periods, 1992 and in the year 2000, to see whether the decision on economics would change, if you were looking at a later period. And the results are robust to the time -- that we are presenting are robust for both time periods.

I should say that there is considerable risk associated with forecasting long-run natural gas prices, or oil prices for that matter, and we are looking to the government for some guidance on the future avoided cost of gas or oil that should be used when making this sort of strategic decision.

I think it is also important for everybody to understand what the implications would be if this forecast proved to be incorrect, and we had a lot of customers on gas that would later like to switch to something else. The implications would not just be for the customers, but they'd also be for the electric utility and the province as a whole.

Q. All right. Now with that treatment of the fuel switching potential and the overlaps in the electrical efficiency improvement area, I want to turn back to you, Mr. Shalaby, and deal for awhile with the load shifting opportunities that exist on Ontario Hydro's system. And I guess my first question is simply to have you advise the panel at to how the load shifting amounts used in the preparation of the Demand/Supply Plan were determined?

MR. SHALABY: A. Well, unlike the electrical efficiency improvement that Mr. Burke spent time explaining how the potential, economic potential

is the term, unlike that process, the load shifting potential is primarily determined by the ability of the electricity system to benefit from the shifting. So the exercise is not looking for economic ways to shift load, but rather how much load shifting is beneficial or has value to the electricity system.

Q. Now why is it that from a system point of view, there is a limit to the amount of load shifting which the system can actually benefit from?

A. To explain that, I'd like to turn to page 52 of Exhibit 260, and I think this is -- this graph here receives the Academy Award for the most appearances in panels. It appeared in Panel 2, Panel 3 and now in Panel 4. Assistant planners cannot go anywhere without one of those.

The graph is showing a daily generation schedule on a cold winter day, and it shows that the demand peaks, or there is a large increase in demand about 7:00 in the morning that remains high until about 11:00 in the evening.

Load shifting is the exercise of moving part of the demand during those high demand hours into what we call the valley. Again, the slide that Mr. Wilson introduced early on showed how a demand management activity is concerned with moving demand

from the peak to the off-peak. So that is a picture that we'd like to keep in mind, to see -- the depth of the valley then is really the limit of how much you can move from the peak to the valley. If you move any more than that, you really build a peak somewhere else. So that is the reason there is a system limitation to do with the potential for load shifting.

Perhaps I can move on to page 53, to graphically illustrate the idea of moving demand from the peak to the valley, just in a three-step illustration.

...

[4:10 p.m.] The top part of the page shows what we call the fossil and base load curve, or the thermal load, the word on that right-hand side, associated with the top graph called the thermal load curve, that is a kind of curve we would like to flatten out. And if we move something like about 1,000 megawatts during the peak hours to the off-peak hours, we end up with a reasonably flat thermal load curve.

Now, the opportunity changes from day-to-day, it changes from season-to-season, it changes as the years go by and the shape of the demand and the size of the demand change.

And Exhibit 25, and particularly appendix E of Exhibit 25, gives a large amount of detail as to what the opportunity is on different types of days, different years, under different load growth assumptions. And perhaps I can summarize some of those conclusions.

If we turn to page 54 of Exhibit 260, this is a summary of the load shifting opportunity extracted from that exhibit, Exhibit 25, and it shows that, if we look at the top line in the diagram which is entitled "median load forecast" on the left-hand side, the left-hand side of the diagram shows the year 2000, so we are now in the upper left-hand corner of

the figures, 1110 megawatts is the opportunity on a high day in the median load forecast. If we go to an upper load forecast, we move directly below that to about 1,380 megawatts.

If we move to the right-hand side of the diagram, year 2008, we see that the opportunity increases. As the entire demand volume increases so does the depth of the valley and the opportunity for load shifting.

Now, you will notice that the numbers are 1100 to 1300 and perhaps up to 1600 in the year 2008 under upper load forecast. The reason our target or our planned load shifting amount is only 1,000 megawatts comes about for various reasons also explained in Exhibit 25 and in Exhibit 76. And the reasons we are content to plan for only 1,000 even though the opportunity is lightly bigger than that is that there is uncertainty about the data that we are using about load shapes and about how that shape varies over time.

There is also a higher value to the first several hundred megawatts. The first hundred megawatts of shifting does us a lot more good than the last hundred megawatts of shifting. And as you approach a limit, you start getting into the 800, 900, 1000

megawatts, you are really approaching an area where you start meeting a risk of shifting the peak to some other time, and the value of that will not be very high.

So, those reasons combine to convince us that a practical limit to plan for at this time is about 1,000 megawatts. And as with every other plan and target, those targets are reassessed and re-evaluated as we gain experience and as we observe the results of load shifting as we go along.

Q. All right. Now, can I then turn over to you, Mr. Harper, and take that thousand megawatt figure and start at it from your side, and perhaps what I would call the customer side. Can you indicate how the estimates for load shifting potential on the customer side were developed?

MR. HARPER: A. Yes. Customers' demands can be shifted from the peak to what we call the valley or the off-peak period either by incentives such as time-of-use rates or through direct load control.

With time-of-use rates it's the price differential between the peak and the off-peak period that encourages a customer to shift his load into the valley.

With direct load control, the utility itself shuts off the loads during the peak period when

electrical equipment such as water heaters where off-peak storage is possible and hence the customer requirements can be still be met with little change in overall service.

As a result, direct load control and time-of-use rates can be therefore viewed as alternatives that are to some extent mutually exclusive. That is, you would use one in a particular application or use the other, but you probably wouldn't use both at the same time.

With this in mind, the potential for load shifting was developed by focusing first on the potential available from time-of-use rates and determining how this potential would stack up against the thousand megawatts of opportunity that had been developed for the year 2000.

Q. And how was the potential available from time-of-use rates estimated?

A. Page 55 of Exhibit 260 outlines the process that we followed.

The potential was estimated by starting with the loads by rate class, that is the direct and the large users, the direct customers being those customers over 5 megawatts that we serve, the large users being over 5 megawatt customers that the

municipal utilities serve. They sort of form a homogeneous class of customers.

We then looked at them. We looked at the general service class, that's the smaller industrial and commercial customers served by us and the municipal utilities, and finally we identified the loads associated with the residential class.

Having identified those initial starting loads, we then for each rate class identified the peak/off-peak rate differentials that would result from passing time-of-use rates through to that class, that's shown by the first box down on the left-hand side.

We then combined that ratio with estimates of the likely response of customers to time-of-use rates. These estimates were based on experience that we drew on by looking at U.S. utilities and European utilities who have had time-of-use rates in place for a number of years. These estimates were also based assuming all customers were put on time-of-use rates. The estimates were then escalated up to the year 2000 using the load growth.

The details of our analysis are provided in response to Interrogatory 4.7.139. And in the case of the end-use customers over --

Q. Just a minute. That would 4.7.139,

and that would be No. 5 in Exhibit 261. Okay. I'm sorry.

---EXHIBIT NO. 261.5: Interrogatory 4.7.139.

MR. HARPER: In the case of the end-use customers over 5 megawatts, this analysis was supplemented by a more detailed study of individudal industrial sectors and commercial customers so that we could look at each sector in the industrial customer segment separately. This was possible because industrial rates have been applied -- because time-of-use rates have been applied primarily to industrial customers and there was a lot more information available and the types of response and different types of industries.

The results of this subsequent analysis are provided in response to 4.7.4.

THE CHAIRMAN: Have you had that?

MR. B. CAMPBELL: We have, yes.

Q. All right. And could you summarize those results for us, please?

MR. HARPER: A. The results, which are shown at the bottom of page 55 and also reported in Exhibit 25, identified some 567 megawatts of potential for the direct customers and large user class, another 384 megawatts of potential for the general service

class, and 288 megawatts of potential for the residential class, coming to a total of some 1238 megawatts.

Q. Now, does this mean that time-of-use rates can provide all of the load shifting the system can effectively use by the year 2000?

A. No. There are two factors that will influence the overall contribution of time-of-use rates, Ontario Hydro's load shifting targets.

First, there is some uncertainty associated with the load shifting estimates developed to date. In fact, the more detailed analysis I outlined also undertook some sensitivity analysis identifying the fact that when we looked at these U.S. and European jurisdictions, there was a range of estimates provided in terms of what likely customer response was. Using this range of estimates, we actually come up with a range of likely response somewhere from just over 200 megawatts to something in excess of 800 megawatts for the year 2000. So there is is some uncertaintly associated with this.

Second, it's not likely that time-of-use rates will be economic for all customers. For particularly small customers, such as residential or small commercial and general service customers, the

result in the load shifting may not produce sufficient benefit to pay for the extra metering costs involved, and therefore the overall program, if you want to call it that, would not pass the total customer cost test.

In fact, the preliminary results of the residential time-of-use rate experiment we have been carrying out identify that for residential customers, it's probably only those customers with both residential space and water heating for which time-of-use rates would be economic.

Q. Now, if that's the case, are you satisfied that Hydro can still meet its load shifting targets?

A. Yes, I am. First, our original analysis, the numbers I talked about earlier, the 1200 plus megawatts, are almost 25 per cent higher than the 1000 megawatt opportunity. This means that time-of-use rates does not have to be applied to all customers in order to achieve the thousand megawatts.

In fact, depending upon the success for those larger industrial customers, probably only two-thirds of the other two classes would have to be put on time-of-use rates.

Second, Hydro has implemented programs in both the industrial and the commercial sectors to

complement time-of-use rates and assist customers with load shifting.

And finally, as I mentioned earlier, direct load control represents another opportunity for shifting loads in those end-uses where perhaps time-of-use rates is not economic.

Q. Now, I would like, then, to turn to interruptible power. Could you describe for us, please, what interruptible power is?

A. Interruptible power is a peak clipping initiative whereby customers agree to reduce their loads to a predetermined level at the request of the utility and in return receive a discount for any power taken above that predetermined level.

I would like to look at page 56 of Exhibit 260 to give you an example of how this works. The chart here shows the cumulative meter readings of the interruptible customers we had on contract on Monday, December 18th, 1989. You will notice along the bottom horizontal axis are the hours of the day and on the vertical axis is the total megawatt meter readings for the some 40 customers.

Problems with Lennox during the month --

THE CHAIRMAN: Did you say 40 customers?

MR. HARPER: Yes.

THE CHAIRMAN: Thank you.

MR. HARPER: Problems with Lennox during December 1989 lead to a tight supply situation and a need to cut interruptible customers on a number of occasions. On this particular day, the customers were noted typically somewhere between one and two o'clock in the morning that a cut would be required at seven o'clock that day. On this particular date, 20 of the 40 customers were phoned.

Lennox happens to be located east of Toronto and with transmission limitations through the Toronto area, the customers west of Toronto could really not provide any relief to the system and therefore they were not asked to cut. But for those 20 customers that were cut, they were requested to cut at seven o'clock in the morning and the cut lasted the full 14 hours of the day allowed under their contract, so they were restored to firm service or full service again at 2100 hours or nine o'clock at night. And this graph basically illustrates from their meter readings, and you can see how the load on the system dropped off rather dramatically at seven o'clock in the morning as they met the cut order, and then was restored at 2100 hours again when they brought their operations back up to regular service.

This same contract that limits the frequency and duration of the cuts also specifies additional charges that the customers will face in the event that the load is not reduced when and where required.

Interruptible power is typically offered to large customers willing to contract for a minimal amount of megawatts.

While I will be getting into the details of interruptible program later, it's useful to note at this point that Hydro has contracted with customers for for interruptible for over 30 years now and currently offers interruptible power, as Mr. Wilson said, in the form of discount demand service to any customer willing to contract for 5 megawatts or more.

Current contracts total some 1026 megawatts which, with after allowing for the diversity that Mr. Shalaby has talked about, represents some 525 megawatts of relief at the time of the system peak. This, coupled with the interruptible relief available at our Bruce heavy water plant, brings the total current available relief up to 590 megawatts.

MR. B. CAMPBELL: Q. All right. And again can you tell us how you have identified or developed this assessment of the opportunities for

interruptible loads?

MR. HARPER: A. The process we followed for interruptible loads is set out on page 57 of Exhibit 260. We started with an existing forecast for interruptible loads beyond -- which is shown at the top of the page there, beyond which we assumed that the loads would grow at the same rate as general load growth overall. This forecast is shown in Exhibit 25 on page 57.

The forecast was then adjusted for recent contract revisions and also adjusted to eliminate some potential for double counting.

If you either shift load to the off-peak period or reduce load through electrical efficiency improvements, then the load is essentially no longer there and available to put on contract for interruptible power. And since we were escalating the relief at the basic load forecast, we had to make some adjustments in order to remove the possibility of any double counting.

...

[4:27 p.m.] The overall forecast that resulted calls for an increase in relief available to some 641 megawatts as shown at the bottom of page 57 in the year 1995 to 702 megawatts in the year 2000, up to 890 megawatts for the year 2014.

Q. Now, in reviewing the interrogatory submitted on this issue, there seems to have been some question as to why there isn't a greater opportunity for interruptible power in the future, and perhaps you could comment on this point.

A. There are two basic reasons why we feel there is a significantly greater relief available from interruptible power: First, and as I will be talking about later on, while we have expanded the options available to customers and increased the discounts to be commensurate with our current system benefits, the customer's perception of system reliability has also changed.

Increased interruptions during 1988 and 1989 and ongoing concerns about future system reliability have lead customers to anticipate higher frequencies of interruptions. As a result, we expect higher discounts will be required simply to maintain the 1988 contract levels.

Second, we have been marketing

interruptible power to our own direct customers for a number of years, over 30 as I mentioned earlier, such that they are all aware of the option and have likely already considered whether or not they can use it.

As a result, we feel our major opportunity for expanding the interruptible base lies with the large customer served by municipal utilities. This is illustrated by the fact that while there are actually more of these large customers than there are direct customers served by us, only seven out of the 43 customers we currently have under interruptible contracts are municipal utility customers, and they, as shown on page 58, represent only roughly 10 per cent of the contracts we have for interruptible power.

However, our experience to date has also indicated that it is mainly customers in the primary manufacturing industries - that is pulp and paper, mining, chemicals, et cetera, that contract for interruptible power.

Large users only represent about 20 per cent of this type of load and, therefore, while there is some opportunity, we don't believe it is overly significant.

As a result, we believe the forecast presented represents a reasonable estimate of the

potential for interruptible power.

Q. And are there any other peak clipping programs or opportunities that are currently made available?

A. Yes, there are. Currently, a number of municipal utilities exercise direct control over water heaters and there are specific utilities that control other loads, such as plenum, heaters in residential homes and air conditioners.

Q. And why haven't these loads and similar programs been included as part of your opportunity for peak clipping measures such as your discount demand service?

A. These loads are under the direct control of the municipal utilities and the control program is designed to reduce their monthly billing demand and address local distribution problems. This typically involves controlling the loads for some four hours per day for a limited number of days per month.

The result is that the program would produce little, if any, benefit in terms of our overall system avoided cost and system generation given the 16-hour peak that Mr. Shalaby was talking about earlier.

Also, such loads are typically not amenable to longer term control, say, leading up to that 16 hours without significantly inconveniencing the customer.

Q. All right. Now, against all of that background, I want to come back to you for a moment, Mr. Burke, and ask you to summarize the total demand management potential that Ontario Hydro has identified for Ontario by the year 2000.

MR. BURKE: A. The overhead, page 59 of Exhibit 260, summarizes the total of the potential estimates that we have just finished describing. The result is 10,200 megawatts.

I would observe that if 100 per cent of this potential were to be obtained, it would correspond to about a 30 per cent reduction in Ontario Hydro's forecast of year 2000 peak.

MR. B. CAMPBELL: All right. Can I have just a moment, Mr. Chairman?

THE CHAIRMAN: Yes.

---Off the record discussion.

MR. B. CAMPBELL: Mr. Chairman, I know it is 15 minutes earlier or 13 minutes earlier than the time you suggested you needed to break.

The next section we deal with goes

through the five cases that are outlined in Exhibit 258, has a description of those, and I am reluctant to - discusses where they came from and so on - and I am reluctant to launch into them. I think it would be much better if we started with those and worked through them in one chunk.

So, with that indulgence, I would suggest that we break for the day at this point.

THE CHAIRMAN: All right. How close are you to completing your examination?

MR. B. CAMPBELL: I think my estimate was two days and I think we are going to make it in two days.

THE CHAIRMAN: And Ms. Couban, you are ready for Thursday morning, are you?

MS. COUBAN: Yes, I am, Mr. Chairman.

THE CHAIRMAN: And do you have any idea yet how long you are going to be?

MS. COUBAN: I would say at least a day.

THE CHAIRMAN: At least a day?

MS. COUBAN: Yes.

THE CHAIRMAN: All right. That will take us to the end of this week then. All right.

We will adjourn until tomorrow morning at ten o'clock.

MR. B. CAMPBELL: Thank you, Mr. Chairman.

---Whereupon the hearing was adjourned at 4:34 p.m., to be reconvened on Wednesday, the 21st day of August, 1991, at 10:00 a.m.

JAS/RT/JB [c. copyright 1985]